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Transcript Exhibit(s)

Docket#(s): G-04204A-06-0463
G-04204A-06-0013
G-04204A-05-0831

Exhibit # : S1, S2, S3, S5, S6, S7, S8, S9, S10, S11, S12, S15, S16, S17, S18, S20, S22, S23, S24, S25, S26, S27, S28, S30, S31, S32, S33, S34, S35, S36, S37, S38, S39, S40, S41, S42, S43.

EXHIBIT
S-1
Admitted

UNS GAS INC.'S RESPONSES TO STAFF'S TWENTY-SECOND SET OF DATA REQUESTS DOCKET NO. G-04202A-06-0463 April 2, 2007

STF 22-1 Refer to Mr. Dukes' rebuttal testimony at page 3, lines 1-9 and to Mr. Grant's rebuttal testimony at page 27, lines 4-12.

a. Please identify every Arizona utility rate case of which Mr. Dukes, Mr. Grant, UNS Gas and/or UNS Gas' affiliates are aware in the past 10 years in which CWIP was excluded from rate base.

b. Please identify every Arizona utility rate case of which Mr. Dukes, Mr. Grant, UNS Gas and UNS Gas' affiliates are aware in the past 10 years in which Customer Advances was excluded from rate base.

c. Please identify every Arizona utility rate case of which Mr. Dukes, Mr. Grant, UNS Gas and UNS Gas' affiliates are aware in the past 10 years in which Customer Advances was treated as a reduction to rate base.

d. Please identify all prior Arizona utility rate cases of which Mr. Dukes, Mr. Grant, UNS Gas and/or UNS Gas' affiliates are aware in which both CWIP and related Customer Deposits were excluded from rate base.

RESPONSE:

a. Mr. Grant and Mr. Dukes are aware of at least two rate cases where CWIP was not included in rate base, those being the last general rate cases involving Southwest Gas Corporation and Citizens Utilities (Arizona Gas Division). There are likely many more rate cases where CWIP was not included in rate base, but Mr. Grant and Mr. Dukes have no personal knowledge of such cases.

b. Mr. Grant and Mr. Dukes have no personal knowledge of rate cases in Arizona where Customer Advances were excluded from rate base. However, since neither Mr. Grant nor Mr. Dukes examined all of the rate cases decided by the Commission over the past ten years, it is possible that examples of this rate treatment do exist.

c. Mr. Grant and Mr. Dukes are aware of at least two rate cases where Customer Advances were treated as a reduction to rate base, those being the last general rate cases involving Southwest Gas Corporation and Citizens Utilities (Arizona Gas Division). There are likely many more rate cases where Customer Advances were treated in such a manner, but Mr. Grant and Mr. Dukes have no personal knowledge of such cases.

d. With respect to the rate base treatment of CWIP, please see the response to part a. With respect to the rate base treatment of Customer Deposits, Mr. Grant and Mr. Dukes have no personal knowledge of rate cases in Arizona where Customer Deposits were excluded from rate base. However, since neither Mr. Grant nor Mr. Dukes examined all of the rate cases decided by the Commission, it is possible that examples of this rate treatment do exist.

RESPONDENT: Kent Grant and Dallas Dukes

WITNESS: Kent Grant and Dallas Dukes

EXHIBIT
ALL-STATE LEGAL®
S-2
Admitted

UNS GAS INC.'S RESPONSES TO STAFF'S TWENTY-SECOND SET OF DATA REQUESTS DOCKET NO. G-04202A-06-0463 April 2, 2007

STF 22-2 For each CWIP project on which UNS Gas is claiming that there were "directly related" Customer Advances, please provide the following information:

a. Was AFUDC calculated on that CWIP project?

b. How much AFUDC was calculated on the CWIP project.

c. When did the CWIP project commence?

d. When was the CWIP project completed?

e. When was each amount of Customer Advances that UNS Gas is asserting were "directly related' to the CWIP project received?

f. Was the balance for AFUDC reduced by the "directly related" Customer Advances?

  i. If so, show exactly how the balance for AFUDC was reduced by the "directly related" Customer Advances, and how that affected the amount of AFUDC.

  ii. If not, explain fully and in detail why the balance for AFUDC was not reduced by the "directly related" Customer Advances.

g. Provide the Company's procedures for computing AFUDC on CWIP.

h. Identify where, within the Company's procedures for computing AFUDC on CWIP, the procedures for addressing "directly related" Customer Advances are contained.

i. Explain fully the Company's procedures for computing AFUDC on CWIP when there is are "directly related" Customer Advances relating to a particular CWIP project.

RESPONSE: a. - e. See STF 22-2 (a. - e.) on the enclosed CD for an expanded version of the spreadsheet submitted in response to Staff's Data Request STF 11.9. Columns (i) and (j) show the amount of AFDC accrued on the respective project through December 31, 2005 and post

2005, respectively. Column (k) shows the project start date and Column (l) shows the date that the project was completed and went into service. Where the project involves an advance, the project is started on the date that the advance is received. In some instances the requested information is not readily available. The Excel file on the enclosed CD is not identified by Bates numbers.

f. & i. The project balance is not reduced by directly related advances due to the fact that, in the Company's most recent rate case (the basis for current service rates being charged to customers), the end-of-test year balance of customer advances (including those related to CWIP) was deducted from rate base. To also reduce CWIP by directly-related advances for purposes of computing AFDC accruals would constitute a double-counting.

g. The procedure for computing AFUDC accrual rates was provided in response to Staff's Data Request STF 5.51. Please see STF 22-2 (g), Bates No. UNSG(0463)06210, on the enclosed CD for the intercompany memo which explains the procedure for accruing AFUDC on construction work orders.

h. The requested information does not exist within the Company's procedures.

RESPONDENT: Carl Dabelstein

WITNESS: Kent Grant

EXHIBIT

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S-3

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-4 Refer to Mr. Dukes' rebuttal testimony at page 3, lines 1-9, and Mr. Grant's rebuttal at page 27, lines 4-12. Based on the knowledge of Mr. Dukes, Mr. Grant, UNS Gas and UNS Gas' affiliates:

a. Admit that UNS Gas has not identified any prior Arizona Corporation Commission decisions in which the ratemaking adjustment recommended by Mr. Dukes was adopted. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

b. Admit that the Arizona Corporation Commission has removed CWIP from utility rate base in many prior utility rate cases. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

c. Admit that the Arizona Corporation Commission has reflected Customer Advances as an offset to utility rate base in many prior utility rate cases. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

d. Admit that the Arizona Corporation Commission has reflected Customer Advances as an offset to utility rate base in many prior utility rate cases, even where CWIP was removed. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

e. Admit that the reason Customer Advances have been as an offset to utility rate base in many prior utility rate cases is that such advances represent non-investor supplied capital. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

f. Admit that UNS Gas accrues AFUDC on construction projects. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

g. Admit that UNS Gas does not reduce the balance for AFUDC by Customer Advances. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

RESPONSE:

a. No. UNS Gas is not aware of any explicit adjustment, similar to that proposed by Mr. Dukes, being referenced in a Commission decision. However, it is likely that similar adjustments to Customer Advances have been proposed and accepted by the Commission without specific reference in a Commission final order. That is because most utilities do not request CWIP in rate base, and therefore any related adjustments to Customer Advances would already be made in the Company's filing, and would not require further adjustment during the course of the rate proceeding.

b. Yes.

c. Yes.

d. Yes, it is typical to reflect at least some balance of Customer Advances as a reduction to rate base. However, as explained in part a. above, it is likely that adjustments to Customer Advances related to CWIP balances have been proposed and accepted by the Commission in prior rate decision.

e. Yes, Customer Advances represent non-investor supplied capital provided to fund the construction of specific capital projects and is subject to refund if certain customer addition levels are met specific to the project. However, it is appropriate to recognize Customer Advances as cost-free capital only to the extent that such advances funded plant that is included in rate base. To reduce rate base for Customer Advances that funded plant and CWIP that are not yet included in rate base would be punitive to the utility.

f. Yes, UNS Gas accrues AFUDC on construction projects.

g. Yes, UNS Gas does not reduce the balance of CWIP by the balance of Customer Advances for purposes of accruing AFUDC.

RESPONDENT: Kent Grant and Dallas Dukes

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

WITNESS: Kent Grant and Dallas Dukes

EXHIBIT

S-5

admitted

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-6 At page 5, line 22, Mr. Dukes states that the expenses were a "substantial one time investment."

a. Admit that the Company's accountants determined that under Generally Accepted Accounting Principles such one time expenditures were an expense, not an investment. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

b. Admit that the vast majority of the substantial one time expenditures were incurred prior to the test year. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

RESPONSE:

a. Based on Generally Accepted Accounting Principles ("GAAP") the GIS expenditures were determined to be an expense item.

b. The GIS "expenditures" were incurred primarily in the years 2003 and 2004. In 2005, during the test year, the GAAP statements were corrected and the expenditures were reclassified to expense and impacted the income of UNS Gas in December 2005.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS, INC.'S RESPONSES TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
SEPTEMBER 11, 2006

1.10 Rate Filing Please provide an electronic copy of the rate filing schedules A-H and all supporting workpapers, with all formulas intact.

RESPONSE: Electronic copies of the rate filing Schedules A-H and all supporting workpapers are provided on the attached CD as RUCO 1.10.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESSES: Karen Kissinger and Dallas Dukes

DATE: October 3, 2005

TO: UNS Gas File

FROM: Steve K. Sims

Background

In 2003 UniSource Energy (UNS) created three subsidiaries to handle the acquisition of the Arizona gas and electric utility properties owned by Citizens Communications. The three subsidiaries are UniSource Energy Service (UES), a holding company, which owns the stock of UNS Gas and UNS Electric, the operating companies. On August 11, 2003, UNS Gas and UNS electric acquired the utility assets from Citizens. Absent an ACC order to the contrary, when a company acquires the operating assets of a utility regulated by the ACC, the acquirer is required to follow the regulatory accounting procedures used by the predecessor company.

UNS is a public company filing quarterly Forms 10-Q and annual reports on Form 10-K with the SEC. UES quarterly and annual financial data is reported in the segment information included in the Forms 10-Q and in the Form 10-K. UNS Gas prepares annual audited financial statements which are provided only to their lenders.

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Issue

UNS Gas undertook a project to locate and GPS all of their existing service lines during 2003-2005 in order to update the data in the UNS Gas Global Information System (GIS). These costs were accounted for as capital costs and partially placed-in-service in 2005 with an in-service date of 12/31/03 with catch-up depreciation of approximately $50,000 recognized as of 8/31/05. The total cost of the project was $897,000 with approximately 83% of the cost, or $747,000, paid to Front Line Energy for locating and GPS'ing the lines. This project took place as a result of an Arizona Corporation Commission (ACC) compliance audit. The ACC compliance audit found that:

Maps available at the time of the audit and used by locating, leak survey, construction and emergency personnel fail to include all service lines.

Per discussion with Carl Dabelstein, Director of Regulatory Accounting, absent an ACC order to defer any costs the accounting treatment of the costs would be consistent with Generally Accepted Accounting Principles (GAAP). The FERC Uniform System of Accounts (USOA) does not specifically prescribe a procedure to be used in accounting for the costs of developing computer software, however, in its Order on Accounting for Pipeline Assessment Costs (copy attached) issued in Docket No. A105-1-000 on June 30, 2005, a specific reference to SOP 98-1 appears in footnote 8 on page 8 thereof. At the fall 2005 meeting of the NARUC Accounting Committee, Carl Dabelstein broached the subject of software development cost accounting with current FERC Chief Accountant, James Guest. Mr. Guest confirmed that, although the accounting has not yet been incorporated into the FERC USOA, that it is his position that companies subject to FERC regulation should follow the requirements of SOP 98-1.

SOP 98-1 – Accounting for the Costs of Computer Software Developed or Obtained for Internal Use – Paragraph .22 states:

The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the application development stage. Data conversion costs, except as noted in Paragraph .21, should be expensed as incurred.

The key guidance has been underlined. Any creation of new data should be expensed as incurred.

The misstatement to the financial statements as of December 31, 2004 is as follows:

UNS Gas/UES/UNS

- Overstatement of Total Utility Plant -$872,000
- Overstatement of Accumulated Depreciation and Amortization - $0
  (Accumulated Depreciation and Amortization is $0 due to the asset not being placed-in-service prior to 2005)
- Overstatement of cumulative Net Income of $527,000 of which $63,000 relates to 2003
- Understatement of cumulative Other Operations & Maintenance - $872,000

In accordance with Accounting Principles Board No. 20, *Accounting Changes,* (APB20) the misstatement is considered to be a correction of an error and should be accounted for as such. Paragraph 38 of APB 20 provides guidance on evaluating materiality of errors and states in part,

> "...a number of factors are relevant to the materiality of ... corrections of errors, in determining both the accounting treatment of these items and the necessity for disclosure. Materiality should be considered in relation to both the effects of each change separately and the combined effect of all changes. If a change or correction has a material effect on income before extraordinary items or on net income of the current period before the effect of the change, the treatments and disclosures described in this Opinion should be followed. Furthermore, if a change or correction has a material effect on the trend of earnings, the same treatments and disclosures are required. A change which does not have a material effect in the period of change but is reasonably certain to have a material effect in later periods should be disclosed whenever the financial statements of the period of change are presented."

Discussion

The following analysis reflects UNS, UES, and UNS Gas consolidated financial information. UNS Gas is a reportable business segment and contributes approximately 11% to UNS's consolidated operating revenues and comprises approximately 6.3% of its consolidated assets.

Financial Statements

In considering the materiality of the misstatement both quantitative and qualitative aspects need to be considered.

UNS Gas

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 8,382	1.25%	$ 63	$1,077	5.85%
2004	767	23,009	3.33%	463	5,703	8.12%
Total Misstatement	$ 872	$31,391	2.78%	$ 526	N/M	N/M

2.

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$ 167,871	$ (872)	$166,999	0.52%
Accumulated Depreciation and Amortization	(6,893)	0	(6,893)	0%
Total Utility Plant - Net	160,978	(872)	160,106	0.54%
Total Assets	201,353	(872)	200,481	0.44%

UNS Gas financial results are reported annually in audited financial statements prepared for lenders. The key impact to be considered is UNS Gas' ability to meet the financial covenants of the credit facilities and not the results of operations or the net income contribution to UNS Shareholders. As discussed below, the ability to satisfy these covenants has not been meaningfully affected by the misstatement. Based on the foregoing, the misstatements to the annual 2003 and 2004 financial statements are deemed to be immaterial.

UES

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	**Other O&M as Reported (Unadjusted)**	**% of Reported Other O&M**	**Net Income Over/(Under) Statement**	**Net Income as Reported (Unadjusted)**	**% of Reported Net Income**
2003	$ 105	$ 16,973	0.62%	$ 63	$3,010	2.09%
2004	767	46,984	1.63%	463	10,047	4.61%
Total Misstatement	$ 872	$63,957	1.36%	$ 526	N/M	N/M

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$284,271	$ (872)	$283,399	0.31%
Accumulated Depreciation and Amortization	(19,789)	0	(19,789)	0%
Total Utility Plant - Net	264,355	(872)	263,483	0.33%
Total Assets	336,131	(872)	335,259	0.26%

UES annual audited financial statements are provided to the lenders of UNS Gas and UNS Electric. UNS Gas financial results are also reported quarterly and annually in the segment information provided in the Forms 10-Q and Form 10-K. The annual information provided in the Form 10-K only reports Net Income. The segment footnotes in the UNS Form 10-Q report Income Before Income Taxes and Net Income for the quarterly and year-to-date periods appropriate for the quarter, and Total Assets as of the end of the quarter. Based on the above with O&M being understated by a maximum of 1.63%, a Net Income maximum misstatement of 4.61% and a Total Asset misstatement of .26%, it is not believed that any segment differences would have misled investors or changed their investment decision. The key impact to be considered is UNS Gas' ability to meet the financial covenants of the credit facilities, discussed below.

UNS

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 216,323	0.05%	$ 63	$46,470	0.14%
2004	767	252,711	0.30%	463	45,919	1.01%
Total Misstatement	$ 872	$469,034	0.19%	$ 523	N/M	N/M

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$3,873,467	$ (872)	$3,872,595	0.02%
Accumulated Depreciation and Amortization	(1,348,017)	0	(1,348,017)	0%
Total Utility Plant - Net	2,081,137	(872)	2,080,265	0.04%
Total Assets	3,175,518	(872)	3,174,646	0.03%

Based on the foregoing, the misstatements to the 2003 and 2004 UNS income statements are deemed to be immaterial. The misstatements attributable to the quarterly periods for UNS (the impacts of the misstatement in each quarterly period beginning in the third quarter of 2003 through 2004 are outlined in Appendix A) are also considered to be immaterial as Net Income is not misstated in any quarterly period more than 1.29%. Based on an annualized quarterly amount, the 2004 misstatement of Net Income is only 1.01%. Based on these considerations, the misstatement to the UNS income statement attributable to 2003 and 2004 are deemed to be immaterial.

Based on the foregoing, the misstatements to the December 31, 2004 balance sheets are deemed to be immaterial as the misstatement to Total Utility Plant was .02% and to Total Assets of .03%

Impact on Third Quarter 2005

As provided for in Staff Accounting Bulletin Topic 5.F., we must consider the impact on the third quarter and nine months ended September 30, 2005 results for UNS if the misstatement is corrected in September 2005. The misstatement amounts shown below are net of the catch-up depreciation that has been recognized for the portion of the asset that was placed in-service on July 19, 2005 with an in-service date of 12/31/03.

UNS Gas is a small segment of UNS Consolidated at 6.3% of total assets. The third quarter 10-Q segment disclosure for UNS Gas net income is $2,000,000 which includes this write-off. As such, the write-off amount is considered immaterial to the segment disclosure. Year-end 2005 impact of this adjustment combined with other adjustments for UNS Gas will be addressed in a separate memo.

UNS	3rd Quarter 2005 Projected Unadjusted	Misstatement	As Adjusted	% of Adjusted Amount
Other O&M	$56,703	$ 847	$57,550	1.47%
Total Operating Expense	286,571	847	287,418	0.29%
Operating Income	56,701	(847)	55,854	1.52%
Net Income	15,733	(542)	15,191	3.57%

UNS	Nine Months Ended September 30, 2005 Projected Unadjusted	Misstatement	As Adjusted	% of Adjusted Amount
Other O&M	$179,444	$ 847	$180,291	.47%
Total Operating Expense	763,569	847	764,416	0.11%
Operating Income	141,223	(847)	140,376	.60%
Net Income	21,418	(542)	20,876	2.60%

The quantitative effects on the quarterly and nine-month periods ended September 30, 2005 reflect a change from reporting approximately $21.4 million and $15.7 million of Net Income to reporting approximately $20.9 million and $15.2 million of Net Income, respectively. Further, as outlined above, the misstatements to Total O&M, Total Operating Expense and Operating Income are NOT considered quantitatively material as NONE of the impacts exceed 1.52%. The correction of the error in the third quarter does not result in a material impact on Net Income.

As previously noted, in evaluating the materiality of a misstatement, qualitative considerations need to be considered as well as the quantitative aspects. SEC Staff Accounting Bulletin 99 – Materiality (SAB 99) provides both quantitative and qualitative guidance as to whether a financial statement change should be considered material. In evaluating qualitative aspects, SAB 99 indicates that the registrant should consider whether the misstatement arises from an item capable of precise measurement or whether it arises from an estimate. In addition, SAB 99 asks the registrant to consider whether the misstatement or change has any of the following implications:

- Masks a change in earnings or other trends;
- Hides a failure to meet analysts' consensus expectations for the enterprise;
- Changes a loss into income or vice versa;
- Affects compliance with regulatory requirements;
- Affects compliance with loan covenants or other contractual requirements;
- Increases managements' compensation; or
- Conceals an unlawful transaction.

Due to the immateriality of the error to UNS, we do not believe that the error masks a change in earnings, does not hide a failure to meet analysts' consensus expectations for the enterprise, it does not change income into a loss, it does not affect compliance with regulatory requirements, it did not increase management compensation and does not conceal an unlawful transaction. The affect on compliance with loan covenants is discussed below.

UNS Gas Debt Compliance

We have reconsidered UNS Gas interest coverage ratio, capitalization ratio and net worth tests related to all financial covenants of their credit agreements, noting that these adjustments would not have affected compliance with any of these loan covenants as follows:

- The interest coverage ratio is a ratio of EBITDA to Interest Expense (excluding the effect of Debt AFDC). EBITDA is overstated as a result of this misstatement. EBITDA before adjustment was \$8M in 2003 and \$24M in 2004. The pre-tax adjustment of \$105K and \$767K in 2003 and 2004, respectively, would not significantly affect the ratio.

- The capitalization ratio is a ratio of total indebtedness to total capitalization. Since total capitalization was overstated, this means that UNS Gas' debt as a percent of total capitalization would have increased in each period, had the adjustment been made in 2004. However, UNS Gas Total Assets misstatement of .26% would not have materially changed the ratio.

- UNS Gas actual net worth test compares actual net worth to a minimum amount. In all cases, although Net Income decreased after adjusting for the misstatement, the net worth amount would be lower in each period but would still have met minimum requirements.

There are no dividend restrictions or other contractual requirements that would have been affected by the misstatements. In each year, our performance would have been slightly worse. However, we were well within compliance with all applicable requirements, a slight decrease would have made no difference in the evaluation of UNS Gas, UES or UNS's operations. Further, it would not have been in management's personal interest to overstate earnings in any period nor would it have impacted their compensation. In addition, this error was not the result of any fraudulent activity or made in an attempt to conceal an unlawful transaction.

Summary of Financial Statement Impact

In addition, we considered financial measures that investors believe are significant and place reliance on in making their investment decisions. This includes not only GAAP measures such as Cash Flows from Operations and the Ratio of Earnings to Fixed Charges (RETFC), but certain non-GAAP measures such as Adjusted EBITDA as outlined in Item 6 of our 2004 Annual Report on Form 10-K. This change would not have any impact on Cash Flows from Operations or EBITDA and based on recalculating the RETFC, the misstatement did not have a significant or adverse impact on this measure. Accordingly, we do not believe that this change would have an impact on investor decisions. No qualitative considerations that would affect the decisions of a financial statement reader have been identified.

Based on the foregoing considerations, and also taking into account the following matters, the misstatement is not deemed to be qualitatively material for the quarter or nine months ended September 30, 2005: The misstatement does not mask any identifiable trends in UNS' third quarter earnings. Further, because of the seasonal nature of UNS's operations, projections provided to analysts are provided only on an annual basis. Analysts and investors are primarily concerned with the cash flows of the company and the misstatement has no effect on the reported or future cash flows. Further, to the extent that there are investors looking at earnings per share, there are many other variable factors in the operations of UNS that can have significant effects on EPS and we do not believe that the effect of recording the misstatement in the second quarter of 2005 masks any trends in EPS. Accordingly, we do not believe that the misstatement has a material impact on the quarter or nine months ended September 30, 2005.

Based on our consideration of both the quantitative and qualitative effects of the misstatement, we believe that the information above supports the conclusion that the financial statement differences are not material to the financial statements as of September 30, 2005 or for the quarterly period and nine months then ended. Note that ABP 28, *Interim Financial Reporting,* paragraph 29 requires disclosure of corrections that are material with respect to an interim period even though they are not material to the estimated income for the year or to the trend of earnings. Because the corrections are not considered material to the quarter and nine months ended September 30, 2005, no disclosures in our Third Quarter Report on Form 10-Q are considered necessary.

Internal Controls

On June 5, 2003, the SEC issued final rules under Section 404 of the Sarbanes-Oxley Act requiring companies to file in their annual reports, a report of management on the company's internal control over financial reporting. Part of the required content in the report is a disclosure of any material weaknesses in the system. An internal control deficiency is a flaw in either the design or operation of a control policy or procedure that has a negative effect on this process. Consequently, we must determine if the internal control deficiency is inconsequential, significant or material.

As previously noted, the misstatement is not deemed to be material to the financial statements for the year or the quarter ended September 30, 2005. In addition, the misstatements were not intentional and have a nominal effect on earnings.

The Public Company Accounting Oversight Board (PCAOB) provides guidance for evaluating control deficiencies in Standard No. 2 as updated as of December 3, 2004 (AS2). Paragraph 23 of AS2 indicates that "The same conceptual definition of materiality that applies to financial reporting applies to information on internal control over financial reporting, including the relevance of both quantitative and qualitative consideration." In addition, we need to consider the likelihood that the deficiency could result in a misstatement and the magnitude of the potential misstatement. Several factors affect the likelihood including the nature of the related accounts, the cause of known exceptions, and the possible future consequences.

Based on review of the relevant considerations, we have concluded that an error of this kind is unlikely to happen again. The misstatement occurred due to a transfer of a task and the continued use of that task for cost accumulation from Citizens at acquisition. A second task for the work was created by Plant Accounting personnel prior to institution of the Capital Work Order Approval decision tree. The process of using the Capital Work Order Approval decision tree along with CON-GA-17 "Computer Software Costs" would have identified the work order as O&M and alerted the Plant Accounting personnel to the incorrect conversion and use of the previous work order. Steps have been taken to ensure that current Plant Accounting staff have been adequately trained on CON-GA-17 and its' implications when making the Capital vs O&M decision. During 2004, management evaluated and tested controls in place to ensure compliance with GAAP. Our testing of both the design and effectiveness of such controls noted no deficiencies.

Because the appropriateness of our accounting for the UNS Gas "GPS and Locate" costs was reconsidered in connection with UNS Electric's request to do the same task, our evaluation of the magnitude of a potential error should consider how in the absence of such analysis we would have identified the misstatement. Our current control processes require the completion of a Plant Accounting Work Order Creation - Capital Work Order Approval Decision Tree that is checked and reviewed for task creation. This review was not conducted in 2003 when the tasks were migrated from Citizens to TEP at the time of acquisition on August 11, 2003. Accordingly, in drawing a conclusion as to the maximum amount of potential misstatement we believe that the current process would have identified the task as O&M on the front end and appropriately charged to O&M.

Based on the foregoing, we do not believe that the control deficiency is material and therefore the deficiency does not constitute a material weakness. Note however, the deficiency is considered to be a significant deficiency and will be appropriately reported to the audit committee as well as the independent auditors.

Conclusion

We have carefully considered both quantitative and qualitative aspects of the misstatement of the UNS Gas "GPS and Locate" costs and believe that the error is not material to the respective financial statements for all periods considered. Accordingly, it is deemed acceptable to record the correcting adjustment in the third quarter of 2005.

cc: Peggy Denny, Karen Kissinger, Dave Grzybowski, Brian Hagues (PwC), David Eberhardt (PwC)

7.

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-8 Refer to Mr. Dukes' rebuttal testimony at page 9.

a. When was the PEP in its current form first implemented by UNS Gas?

b. Please provide all quantifications the Company has of the reductions in vacation pay, sick pay, long-term disability, 401k matching, pension expense and other post-retirement benefits expense.

c. Please provide the annual base wage increases, for each employee group, that the Company has implemented since implementing PEP.

RESPONSE:

a. The PEP program has been a part of unclassified UNS Gas employees' fair and reasonable compensation since the inception of UNS Gas.

b. By segregating part of fair and reasonable compensation into an incentive program, the expenses for vacation pay, sick pay, long-term disability, 401k matching, pension expense and other post-retirement benefits expenses have not escalated as they would have had all compensation been earned as part of base pay from the beginning. By implementing the incentive program from the first day of UNS Gas' operations, these costs have been reduced in comparison to what the cost would have been if all fair and reasonable compensation was paid in the form of base wages.

c. Non-union employees who are eligible for PEP received the following annual base wage increases: October 1, 2003 - 3.5%; January 10, 2005 - 3.0%; and January 9, 2006 - 3.0%.

RESPONDENT: HR Services Group

WITNESS: Dallas Dukes

EXHIBIT
S-8
Admitted

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-9 At page 7 of his rebuttal testimony, Mr. Dukes refers to a recent Commission Decision No. 68487 (February 23, 2006) in a Southwest Gas Corporation rate case. Is Mr. Dukes disputing that the Commission disallowed 50 percent of the incentive compensation of Southwest Gas Corporation in that recent decision? If so, explain fully.

RESPONSE: No. Mr. Dukes is not disputing that the Commission disallowed a portion of Southwest Gas Corporation's "management" incentive compensation program based on the facts and circumstances of that particular companies' filing.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-11 Refer to Mr. Dukes' rebuttal at page 12.

a. Provide a copy of the Deferral Compensation Plan.

b. Does the Deferral Compensation Plan allow officers, directors and managers to defer a higher percentage of their compensation than is permissible through the Company's 401k plan? If not, explain fully.

c. What percentage of compensation can officers, directors and managers defer under the Deferred Compensation Plan?

d. What percentage of compensation can officers, directors and managers defer under the 401k plan?

e. Is the Deferral Compensation Plan a qualified plan under the Internal Revenue Code and Treasury Regulations? If not, explain fully. If so, please identify the provisions of the Code and Regs under which it qualifies.

f. Is the Deferral Compensation Plan a discriminatory plan, in that it is limited only to directors, officers and managers?

g. Please describe the eligibility for the Deferral Compensation Plan.

RESPONSE:

a. Please see STF 22-11, Bates Nos. UNSG(0463)06221 to UNSG(0463)06255, on the enclosed CD for a copy of the Deferred Compensation Plan Document.

b. The Deferred Compensation Plan does allow eligible officers, directors and managers to defer a higher percentage of their compensation than is permissible through the Company's 401(k) Plan.

c. Subject to the minimum deferral provisions, the amount of Compensation which an Eligible Employee selected in accordance with Section 2.1 or Director may elect to defer is as follows:

(1) Any percentage of Salary up to 100%; and/or
(2) Any percentage or dollar amount of Bonus up to 100%;

d. Eligible TEP officers and managers may defer up to 25% of salary and bonus under the 401(k) Plan. Eligible UNS Gas managers may defer up to 50% of salary and bonus under the 401(k) Plan. In both instances referenced above, deferrals may not exceed the annual IRS Code deferral limits (in 2005 the annual limit for participant elected deferrals was $14,000.) All participants age 50 and over are eligible to contribute Catch-up Contributions up to an additional 50% of salary and bonus, not to exceed the annual IRS Code limit (in 2005 the annual limit for Catch-up Contributions was $4,000.) Directors are ineligible to defer compensation under the 401(k) Plan.

e. The Deferred Compensation Plan is a non-qualified plan under the Internal Revenue Code.

f. The Deferred Compensation Plan is a discriminatory plan, in that it is limited only to eligible directors, officers and managers.

g. See attached Plan Document provided in part (a) above for description of eligibility for the Deferred Compensation Plan.

RESPONDENT: HR Services Group

WITNESS: Dallas Dukes

**UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007**

STF 22-13 Refer to Mr. Dukes' rebuttal at page 12-14 concerning SERP.

a. Is Mr. Dukes disputing that the Commission disallowed the SERP expense of Southwest Gas Corporation in that recent decision? If so, explain fully.

b. Admit that the UniSource SERP expense at issue in the current UNS Gas rate case is similar to the Southwest Gas Corporation SERP for which the expense was disallowed by the Commission in Decision No. 68487. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

RESPONSE:

a. No. Mr. Dukes is not disputing that the Commission disallowed expenses entitled SERP expense in Decision No. 68487 based on the facts and circumstances of that particular companies' filing.

b. Mr. Dukes is not familiar with Southwest Gas Corporation's SERP program and cannot provide an accurate comparison. It also would be imprudent to compare the proper regulatory treatment of SERP program expenses in isolation without considering all factors affecting the level of executive compensation for both companies.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

EXHIBIT

S-11

Admitted

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-19 Refer to Exhibit JDJ-1.

a. Provide complete documentation, including invoices and accounting records, for all rate case expense proposed by the Company.

b. Show in detail how UNS Gas computed the $300,000 it is now claiming for rate case expense.

RESPONSE:

a. Please see the response to RUCO 1.06, including the Supplemental Responses filed January 4, 2007 and March 26, 2007.

b. The $300,000 is an updated placeholder assuming $900,000 in total rate case expense being amortized over three years. The $900,000 is based on the balance as of February 28, 2007 in deferred rate case expense of $786,556 and an estimate of the costs that UNS Gas will incur in additional rate case expense to finalize the process. This of course is dependent upon the time spent preparing rebuttal, reviewing surrebuttal, preparing rejoinder, preparing for the hearing, the hearing itself and responding to data requests.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS, INC.'S RESPONSES TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
SEPTEMBER 11, 2006

1.06 Rate Case Expense Please provide the following information regarding rate case expense:

a) What amount of proforma rate case expense is the Company requesting in this docket?
b) How much rate case expense is embedded in the actual test year and in what account?
c) How much rate case expense does the Company expect to incur associated with this docket?
d) How long does the Company anticipate the rates set in this docket will be in effect?
e) Identify each item of rate case expense incurred to date and provide supporting documentation; and
f) Provide monthly updates.

RESPONSE:

a) The Company is requesting the recovery of all prudently incurred outside costs directly related to the conduct of this rate case. The Company has included an estimate of $600,000 in rate case expense to be recovered over a three-year amortization period.

b) There is no rate case expense embedded in the actual test year.

c) The Company has not revised its estimate of $600,000 at this time.

d) The Company anticipates the rates set in this docket will be in effect for three years.

e) Outside costs incurred as of August 31, 2006:

TEP Labor	$	247,980
TEP Labor Taxes	$	16,320
TEP Labor Loads	$	109,607
Other Outside Services	$	130,236
	$	504,143

Attached as RUCO 1.06(e) is a CD containing supporting documentation. RUCO 1.06(e) is being provided pursuant to the terms of the Protective Agreement. The files on the CD responsive to RUCO 1.06(e) are not identified by Bates numbers.

f. Monthly updates of rate case expense revisions will be provided when applicable.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

EXHIBIT
S-12
Admitted

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-16 Please provide the complete AGA Budget document mentioned by Mr. Dukes at page 18,k line 24 of his rebuttal.

a. Please provide the corresponding 2005 and 2006 AGA budget documents.

RESPONSE: Please see STF 22-16, Bates Nos. UNSG(0463)06256 to UNSG(0463)06257, on the enclosed CD. It contains the information provided by the AGA to the Company.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

Zaidenberg-Schrum, Janet

From: Allen, Doug [DAllen@aga.org]
Sent: Thursday, February 15, 2007 3:18 PM
To: Zaidenberg-Schrum, Janet
Subject: RE: Member Dues Detail

Janet, I've attached a schedule that breaks down AGA's 2007 budget by major program area.

The most recent information that I have for the lobbying percentage of AGA dues is 2005. AGA incurred lobbying expenses, as defined under IRC Section 162, of 1.88% in 2005. We estimate that lobbying related expenses will account for 2% of total member dues in 2006 and 2007.

I'll be traveling the rest of the week and won't return until Tuesday, February 20th. If you need additional assistance, please contact AGA's CFO, Kevin Hardardt, for more information. I already talked to Kevin about your inquiry and said he can answer any questions that you might have. Kevin's phone number is (202) 824-7250 and his email address is khardardt@aga.org

Thank you.

Doug

Douglas C. Allen
Director, Finance & Accounting
American Gas Association
400 N. Capitol Street, NW
Washington, D.C. 20001

Phone: (202) 824-7261 Fax: (202) 824-7085
E-mail: dallen@aga.org

AMERICAN GAS ASSOCIATION
2007 BUDGET

	$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	$345,000	1.39%
Corporate Affairs	$2,099,000	8.44%
General & Administrative	$4,665,000	18.77%
General Counsel	$1,016,000	4.09%
Industry Finance & Administrative Programs	$1,283,000	5.16%
Operations & Engineering Management	$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	$3,669,000	14.76%
Public Affairs	$5,790,000	23.29%
Total Budget	$24,860,000	100.00%

EXHIBIT
S-15
Admitted

UNS GAS INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 9, 2007

STF 22-10 Refer to Mr. Dukes' rebuttal testimony at page 11.

a. Provide a complete copy of all documentation provided to the Board in determining compensation levels for Officers.

b. Admit that setting officer compensation at 75% of a peer group, in itself, will tend to result in above average compensation cost for TEP officers. If your response is anything but an unqualified admission, explain fully and provide the supporting documentation relied upon for your answer.

c. Please identify all companies in the peer group.

d. Please explain fully why only 75% of the selected peer group is used.

e. For the 25% of the peer group that was excluded, what was the officer compensation? Identify for each position studied.

f. For the 75% of the peer group that was used, what was the officer compensation? Identify for each position studied.

g. Explain fully the basis for excluding 25% of the peer group in setting TEP officer compensation.

h. Is the TEP officer compensation set higher than the median of the entire peer group (i.e., at 100% of the peer group).

i. Please provide (1) the total TEP officer compensation, (2) the TEP officer compensation if set at the median of the entire peer group, (3) the difference, and (4) the impact of the difference on UNS Gas expense in the 2005 test year.

j. Please provide a complete itemization of all salary, compensation and benefits for TEP officers and the total cost of each component of officer compensation for each TEP officer.

k. For each item in part g, please provide the related impact on UNS Gas for the 2005 test year by account.

RESPONSE: a. UNS Gas is in the process of gathering this information and will provide it shortly.

b. Target compensation is the median (50^{th} percentile) of the entire peer group, meaning that 50% of companies pay more and 50% of the companies pay less. Average is not the benchmark for compensation or performance. Individual compensation may vary according to attributes such as performance, length of time in the position, experience, education, knowledge, skill, ability, recruitment and retention issues. Board members review pertinent information and use their best judgment for fair and reasonable compensation necessary to recruit and retain the executive talent critical to achieving business goals. Please see STF 22-10 (b), Bates Nos. UNSG(0463)06267 to UNSG(0463)06277, for more discussion on this topic.

c. The peer group companies are AGL Resources, El Paso Electric, South Jersey Industries, Avista, IDACORP, Southern Union, CH Energy Group, Northwest Natural Gas, Southwest Gas, Cleco, Otter Tail, UIL Holdings, DPL, PNM Resources, Westar Energy and Duquesne Light.

d. 100% of the selected peer group was used in the study. 75% refers to the 75^{th} percentile of the entire peer group.

e. None of the peer group was excluded and the data was reported in the aggregate by the outside consulting firm.

f. None of the peer group was excluded and the data was reported in the aggregate by the outside consulting firm. Please see STF 22-10 (f) on the enclosed CD for the officer compensation for the entire peer group. STF 22-10 (f) contains confidential information and is being provided pursuant to the terms of the Protective Agreement. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

g. None of the peer group was excluded. See answer to part d. above.

h. Target compensation is the median (50^{th} percentile) of the entire peer group, meaning that 50% of companies pay more and 50% of the companies pay less. Average is not the benchmark for compensation or performance. Individual compensation may vary according to attributes such as performance, length of time in the position, experience, education, knowledge, skill, ability, recruitment and retention issues. Board members review pertinent information and use their best judgment for fair and reasonable compensation necessary to recruit and retain the executive talent critical to achieving business goals. Please see STF 22-10 (b) for more discussion on this topic.

i. Please see STF 22-10 (i) on the enclosed CD for (1) the total TEP officer compensation, (2) the TEP officer compensation if set at the median of the entire peer group, (3) the difference, and (4) the impact of the difference on UNS Gas expense in the 2005 test year. STF 22-10 (i) contains confidential information and is being provided pursuant to the terms of the Protective Agreement. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

j. Please see STF 22-10 (j) for an itemization of all salary, compensation and benefits for TEP officers and the total cost of each component of officer compensation for each TEP officer. STF 22-10 (j) contains confidential information and is being provided pursuant to the terms of the Protective Agreement. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

k. Not applicable, there are no items in part g.

RESPONDENT: HR Services Group

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE:

a. Please see STF 22-10 (a), Bates No. UNSG(0463)06680 to Bates No. UNSG(0463)06710, and the Excel file on the enclosed CD for a copy of the Executive Compensation Competitive Compensation Review prepared for the Compensation Committee of the Board of Directors. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

Bates Nos. UNSG(0463)06680 to UNSG(0463)06710 and the Excel file contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: HR Services Group

WITNESS: Dallas Dukes

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee is made up of six directors who are independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards. The Board previously adopted a written charter for the Compensation Committee. The Compensation Committee Charter is available for inspection on the Company's website at www.UNS.com. The Compensation Committee is in compliance with its charter.

The Compensation Committee has reviewed and discussed with management the "Compensation Discussion and Analysis" section required by Item 402(b) of SEC Regulation S-K and contained in this Proxy Statement. Based on such review and discussions, the Compensation Committee recommended to the Board that the "Compensation Discussion and Analysis" section be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006 and the 2007 Proxy Statement.

Respectfully submitted,

THE COMPENSATION COMMITTEE

Harold W. Burlingame, Chair
Barbara M. Baumann
John L. Carter
Daniel W. L. Fessler
Warren Y. Jobe
Joaquin Ruiz

The following Compensation Discussion and Analysis contains statements regarding future individual and Company performance targets and goals. These targets and goals are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

COMPENSATION DISCUSSION AND ANALYSIS

COMPENSATION PHILOSOPHY

Objectives of the Compensation Program

We base our executive compensation policies and decisions with respect to our Named Executives on the achievement of the following objectives:

1. Attract, motivate and retain highly-skilled executives;

2. Link the delivery of compensation to the achievement of critical short- and long-term financial and strategic objectives, creation of shareholder value and provision of safe, reliable and economically available electric and gas service;

3. Align the interests of management with those of our stakeholders and encourage management to think and act

like owners, taking into account the interests of the public that the Company serves;

4. Maximize the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and
5. Encourage management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance best practices.

In support of the above objectives, UniSource Energy provides a balanced total compensation program that consists of four components:

- base salary;
- short-term performance-based incentive compensation;
- long-term performance-based incentive compensation; and
- benefits and perquisites.

Each of these components is described in more detail below. The following illustrates how the above objectives are reflected in our compensation program:

Attracting, Retaining and Motivating Executive Talent

In support of our objective to attract, retain and motivate highly-skilled employees, we provide our Named Executives with compensation packages that are competitive with those offered by other electric and gas services companies of comparable size and complexity.

The Compensation Committee generally targets base salary and short-term incentive opportunities, as well as the allocation among those elements of compensation for the Named Executives, at the median market rates of selected comparable companies. Long-term incentive opportunities are targeted at the 75th percentile of such market rates. Target compensation for individual executives range above or below those benchmarks based on a variety of factors, including each executive's skill set and experience relative to the general market, the importance of the position to the Company and the difficulty of replacing the executive, and the executive's past and expected future contribution to our success.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below.

Linking Compensation to Performance

Our compensation program seeks to link the actual compensation earned by our Named Executives to their performance and that of the Company. We achieve this goal primarily through two elements of our compensation package: (i) short-term cash awards and (ii) equity-based compensation. To ensure that the most senior executives are held most accountable for achieving our financial, operational and strategic objectives and for creating shareholder value, we believe that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs (i.e., cash incentive and equity-based compensation) comprise approximately 55% to 65% of the total direct compensation opportunity for our Named Executives. Non-variable compensation, such as salary and perquisites, are de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Aligning the Interests of our Named Executive Officers with Stakeholders

Our compensation program also seeks to align the interests of our Named Executives with those of our key stakeholders, including customers, employees and shareholders. We use the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for our employees and improving financial performance by linking a significant portion of their short-term cash incentive compensation to achievement of these objectives. We primarily rely on the equity compensation element of our compensation package to align the interests of the Named Executives with those of shareholders through a mix of stock options and stock awards that vest based on the achievement of performance goals set by the Compensation Committee. We also encourage senior executives to accumulate a substantial stake in the Company.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for our Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives and delivery of value to shareholders. In addition, the Compensation Committee takes into account the objective of having the incentive-based compensation components qualify for tax deductibility under Section 162(m) of the Internal Revenue Code, as amended (the "Code"). See discussion under "Impact of Regulatory Requirements" on page 19. The Compensation Committee also considers the cash flow and share dilution implications of cash versus equity-based incentive plans. In managing overall costs under the variable incentive plans, the Compensation Committee sets annual budgets with regard to total expense and the dilutive impact on shareholders. These budgets are set at levels determined to be reasonable and sustainable by the Company in relation to costs incurred by peer companies.

Adhering to Corporate Governance Best Practices

The Compensation Committee seeks to continually update the executive officer compensation program to reflect corporate governance best practices. For example, the Compensation Committee has established formal stock ownership guidelines that encourage each Named Executive to accumulate a meaningful amount of Company stock. Additionally, equity-based awards contain a "double-trigger" vesting provision, which provides for accelerated vesting in the event of a future change in control only if the executive is adversely impacted by the transaction.

As the Compensation Committee analyzes and discusses executive compensation in its meetings, it considers certain factors for purposes of establishing salaries and variable compensation opportunities. Factors that are considered in its assessment include the following:

- total compensation, taking into account all equity awards granted since the executive started with the Company, total wealth accumulation and future compensation opportunities, as depicted in tally sheets;
- internal pay equity;
- stock ownership and retention policies, including hold-until-retirement policies;
- competitive environment for Named Executives, and what relevant competitors pay; and
- the need to provide each element of compensation and the amounts targeted and delivered.

Benchmarking

To provide a foundation for the executive compensation program, UniSource Energy participates in an annual executive compensation survey of the energy services industry and periodically reviews the senior executive compensation levels and practices among a peer group of companies intended to represent our competitors for business and talent. The peer group is reviewed periodically and includes the 16 electric and gas utility companies named below that are comparable to UniSource Energy in terms of size as measured by annual revenues and market capitalization. UniSource Energy's revenues and market capitalization are generally consistent with the median of the peer companies.

AGL Resources Inc.	DPL Inc.	Northwest Natural Gas Co.	Southern Union Co.
Avista Corp.	Duquesne Light Company	Otter Tail Power Company	Southwest Gas Corp.
CH Energy Group Inc.	El Paso Electric Co.	PNM Resources Inc.	UIL Holdings Corp.
Cleco Corporation	IDACORP Inc.	South Jersey Industries	Westar Energy Inc.

A comprehensive review of UniSource Energy's executive compensation levels and aggregate long-term incentive cost and share usage practices relative to peer group was most recently conducted in October 2005.

The benchmark information is supplemented with information from Frederic W. Cook and Co., Inc., the independent consultant retained by the Compensation Committee, relating to general market trends, changes in regulatory requirements related to executive compensation and emerging best practices in corporate governance.

ELEMENTS OF COMPENSATION

Base Salary

We believe that competitive base salaries are necessary to attract and retain executive talent critical to achieving the Company's business goals. In general, our Named Executives' base salaries are targeted to the median of the benchmark companies described above. However, individual salaries can and do vary from the benchmark median data based on such factors as individual performance, potential for future advancement, the importance of the executive's position to the Company and the difficulty of replacement, current responsibilities, length of time in the current position, and, for recently hired executives, their prior compensation packages.

Increases to Named Executives' base salaries are considered annually by the Compensation Committee. In approving base pay increases for executives other than the CEO, the Compensation Committee also considers recommendations made by the CEO.

In December 2006, the Compensation Committee approved the following base salary increases for the Named Executives for 2007:

Name	*2006 Base Pay*	*Approved 2007 Base Pay*
James S. Pignatelli	$670,000	$695,000
Kevin P. Larson	$290,000	$300,000
Dennis R. Nelson	$290,000	$295,000
Michael J. DeConcini	$290,000	$300,000
Raymond S. Heyman	$290,000	$300,000

Short-Term Incentive Compensation (Cash Incentive Awards)

The Compensation Committee provides for short-term incentive compensation payments under the Performance Enhancement Plan ("PEP") in order to tie a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance. Each year the Compensation Committee establishes targets that are expressed as a percentage of salary, objective performance criteria that must be met in order for payouts to be made and other terms and conditions of awards under the PEP. Each of these components is discussed below. We typically approve short-term incentive metrics in the first quarter.

The Compensation Committee generally attempts to align target cash incentive opportunities for each Named Executive with the median rate for equivalent positions at the benchmark companies. In 2006, target incentive opportunities under the PEP for the Named Executives ranged from 50% to 80% of base salary, depending on position and were payable in cash. Depending upon achievement of the objective performance goals, a Named Executive's actual payout may be above or below the targeted amount. The maximum potential award for any participant in the PEP, including the Named Executives, was 150% of the target cash incentive amount. For years prior to 2007, the Compensation Committee had the discretion to increase, reduce or eliminate an award regardless of whether the performance goals applicable to the Named Executive's incentive award have been achieved.

In 2006, the performance criteria approved by the Compensation Committee and applicable to all Named Executives and other non-union employees were earnings per share ("EPS"), cost containment ("O&M") and customer service and core business goals relating to customer service, regulatory, reliability and safety. The customer service and core business goals included, among others, customer service response time average at or below 3 minutes, community service of at least 35,000 hours volunteered by employees, Springerville Unit 3 and Luna generation project implementation, various operational reliability goals, and OSHA incident rates at or below national average. The EPS and O&M goals were weighted 30% each and the operational goals were weighted 40%. The EPS range was $1.65 to $2.05 per basic share, the O&M expense range was $228 million to $238 million, and the customer service and core business goals range was 200 to 600 points (which are calculated in accordance with a formula that takes into account the relative weighting of each customer service or core business goal). Each of the three major goals had an individual threshold, and payouts under the PEP can occur along a range of 15% to 150% of target. These measures and the individual weightings were selected by the Compensation Committee to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence. We believe that the cash incentive compensation plan represents the interests of various stakeholders, including customers, employees, and shareholders.

For 2006 performance, the Company achieved its basic EPS goal at a level of 115% of target, or $1.91 per share, its cost containment goal at 75% of target, or $235.5 million, and its customer service and core business goals at 100% of target, or 400 points. Accordingly, the total weighted achievement level was 97% of target for 2006. In February 2007, the Compensation Committee determined that the cash incentive funding under the PEP would be 100%, with adjustments made to individual Named Executive's awards to reflect individual performance.

In February 2007, the Compensation Committee approved the short-term PEP program for 2007. The structure of the 2007 program remains the same as 2006, but certain changes were made, including replacement of Basic EPS with Diluted EPS and greater emphasis on customer service, safety and core business goals.

Long-Term Incentive Compensation (Equity Awards)

We provide long-term incentives in the form of various types of equity awards to help achieve several key compensation objectives. We believe that equity awards, in tandem with our executive stock ownership guidelines discussed below, encourage ownership of Company stock by executive officers, which in turn aligns the interest of those officers with the interest of our shareholders. In addition, the vesting provisions applicable to the awards encourage a focus on long-term operating performance, link compensation expense to the achievement of multi-year financial results and help to retain executive officers.

The UniSource Energy Corporation 2006 Omnibus Stock and Incentive Plan (the "2006 Omnibus Plan") was approved by our shareholders in 2006 and permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, and performance units. This plan gives the Company flexibility in providing competitive long-term incentive compensation.

Annually, during the first quarter, the Compensation Committee approves the long-term incentive awards to be granted for the upcoming year. This includes the type of equity to be granted, as well as the size of the awards for Named Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that will apply, the Compensation Committee considers the strategic goals of the Company, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, the impact on EPS and the number of shares that would be required to be allocated for the award and the resulting impact to shareholders.

Long-term incentive opportunities are expressed as a multiple of salary. The long-term incentive multiple is then applied to the Named Executive's base salary to determine the size of the award. The long-term incentive multiple, which is 100% for each Named Executive, was established in 2003 to retain the executives in light of a then pending merger. The value of the Named Executives' long-term incentive multiples, which is generally consistent with the 75th percentile of benchmark practice, has been maintained for the Named Executives to strengthen the retention value of the compensation program following the termination of the proposed merger transaction in 2004. The impact of the proposed merger transaction on executive officer compensation is described in greater detail in "Elements of Post-Termination Compensation – Change in Control".

During 2004 and 2005, the Company did not have shares available for stock awards under a shareholder approved incentive plan so it adopted a cash incentive based long-term incentive plan ("LTIP") during that period. Under the 2004 LTIP, the Named Executives received payouts based on the achievement of three performance goals during 2004, which were EPS, TEP operating cash flow and UniSource Energy consolidated operating cash flow. The achievement level for the 2004 performance period was 120% of target and the Named Executives received payouts beginning in 2005 in three installments under the 2004 LTIP. The 2005-2007 LTIP is based on the achievement of two performance goals, EPS and UniSource Energy consolidated operating cash flow, over the three-year period 2005-2007. Actual 2005 and 2006 results, together with projections for 2007, indicate that the three-year performance results will likely fall short of the threshold payout level.

For 2006, management recommended and the Compensation Committee approved long-term incentive awards consisting of stock options and performance shares. We believe that our long-term incentive program is well-balanced in that it focuses the Named Executives on increasing shareholder value and achieving longer-term financial goals. Options are designed, in part, to reward longer term success in Company performance that is reflected in increases in share price and performance shares are designed, in part, to reward achievement of financial performance objectives whether or not reflected in actual share price in the short term. In addition, performance shares support important financial efficiency objectives by ensuring that cost is variable and incurred by the Company only to the extent that financial goals are achieved.

The 2006-2008 performance share awards are tied to the achievement of Basic EPS (defined as EPS applied to undiluted outstanding shares) and cash flow goals over a three-year performance period. These goals were selected since they are considered to be the most significant drivers of long-term value creation for our shareholders. The goals are equally weighted and the Named Executives can earn 0% to 150% of the target shares based on actual achievement of the goals. Under the 2006-2008 long-term award, a cumulative Basic EPS range of $5.80 to $6.38 and a cumulative cash flow from operations range of $879.6 million to $901.1 million must be achieved over the

2006-2008 period in order to meet their target. For 2006, Basic EPS was $1.91 per share and cash flow was $282.5 million which will contribute towards the cumulative three-year performance period. These targets and goals are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

The 2006-2008 stock option and performance awards were made in May 2006 following shareholder approval of the 2006 Omnibus Plan. Future long-term incentive awards are expected to be granted by the Compensation Committee during the first quarter following the close of the fiscal year. When the Compensation Committee approves grants of plan-based equity awards, the exercise price is set at the market closing price of UniSource Energy common stock on the date that the grant is made, consistent with recent developments in SEC rules and guidelines. Awards are not coordinated with the release of material non-public information.

In addition, the Company does not typically provide for off-cycle stock option grants and has no specific number of shares under the 2006 Omnibus Plan set aside for such grants. However, occasionally in connection with a new hire of an executive, such a grant may be made to the extent approved by the Compensation Committee. The exercise price of any off-cycle option granted to a newly hired executive will be the closing market price on the date that the Compensation Committee approves any such award, consistent with the pricing practices associated with on-cycle plan-based equity awards.

Stock option grants and performance share awards are intended to qualify as performance-based compensation under Section 162(m) of the Code, which ensures that awards granted to the CEO and other Named Executives are tax deductible by the Company.

In March 2007, the Compensation Committee approved awards of stock options and performance shares to the Named Executives under a 2007-2009 stock option and performance award. The terms of the stock options and the design of the performance share plan are similar to the 2006-2008 long-term incentive program described above, although for the 2007-2009 long-term award, Diluted EPS has replaced Basic EPS.

OTHER COMPENSATION

Perquisites

The Company provides Named Executives with limited personal benefits and perquisites. These are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and overall retention value of the executive compensation program and be responsive to similar benefits provided to executives and other key personnel in other similar companies in the industry. Executive officers, along with managers and certain other supervisory personnel, are provided with the use of a vehicle and related vehicle operating costs of fuel and car insurance are paid for by the Company. In addition, the Company from time to time reimburses certain executives for business or similar social club initiation fees and periodic special assessments. Finally, the Company also reimburses executives for the travel expenses of their spouses incurred in connection with the annual Board strategic retreat.

Retirement Benefits

Our Named Executives are also eligible to participate in certain employee benefits plans and arrangements offered by the Company. These include the Tucson Electric Power Company 401(k) Plan, the Tucson Electric Power Company Salaried Employees Retirement Plan (the "Retirement Plan"), the Tucson Electric Power Company Excess Benefits Plan (the "Excess Benefits Plan") and the Management and Directors Deferred Compensation Plan (the "DCP"). A description of the pension and other retirement plans is provided under "Elements of Post-Employment Compensation-Retirement and Other Benefits," below.

ELEMENTS OF POST-EMPLOYMENT COMPENSATION

Termination and Change in Control

In 1998, TEP, a wholly owned subsidiary of the Company, entered into Change in Control Agreements ("Change in Control Agreements" or "Agreements") with all of the then Named Executives to help keep them focused on their work responsibilities during the uncertainty that accompanies a change in control, to provide benefits for a period of time following certain terminations of employment after a change in control event or transaction and to help us attract and retain key personnel.

For the purpose of the Agreements, a change in control includes the acquisition of beneficial ownership of 30% of the common stock of UniSource Energy, certain changes in the Board, approval by the shareholders of certain mergers or consolidations or certain transfers of the assets of UniSource Energy. The Agreements provide that each officer shall be employed by TEP or one of its subsidiaries or affiliates, in a position comparable to his current position, with compensation and benefits, which are at least equal to his then current compensation and benefits, for an employment period of five years after a change in control (subject to earlier termination due to the officer's acceptance of a position with another company or termination for cause).

The Agreements are in effect until the later of: (i) five years after the date either TEP or the officer gives written notice of termination of the Agreement, or (ii) if a change in control occurs during the term of the Agreements, five years after the change in control. On March 29, 2004, a change in control occurred for purposes of the Agreements when our shareholders, at a special meeting, approved the acquisition agreement that provided for an affiliate of Saguaro Utility Group L.P. to acquire all of our outstanding shares of common stock.

On March 3, 2005, TEP provided the officers of the Company with written notice of termination of the Agreements effective March 3, 2010, the fifth anniversary of the date of the written notice of termination. In December 2006, the CEO of the Company and one other Named Executive, Dennis R. Nelson, waived all rights they otherwise would have had for the remaining effective period under their Agreements and terminated the Agreements to which they and TEP had been party.

During the remaining term of the Agreements currently in effect, in the event that an officer's employment is terminated by TEP (with the exception of termination due to the officer's acceptance of another position or for cause), or if the officer terminates employment because of a reduction in position, responsibility, compensation or for certain other stated reasons prior to March 3, 2010, the officer is entitled to severance benefits in the form of: (i) a lump sum payment equal to the present value of three times the sum of annual salary and target bonus ("cash severance"), (ii) the present value of the additional amount (including any amount under the Excess Benefits Plan) the officer would have received under the Retirement Plan if the officer had continued to be employed for the five-year period after a change in control occurs, plus (iii) the present value of any employee award under the 2006 Omnibus Plan or any successor plan, which is outstanding at the time of the officer's termination (whether vested or not), prorated based on length of service. Such officer is also entitled to continue to participate in TEP's health, death and disability benefit plans for five years after the termination. The Agreements further provide that TEP will make a payment to the officer to offset any golden parachute excise taxes that may be imposed in accordance with Code sections 280G and 4999. Any payments made in respect of such excise taxes are not deductible by us. Cash severance would also be paid under the Agreements if an officer dies or becomes disabled prior to March 3, 2010. Refer to "Potential Payments upon Termination or Change in Control" on page 27 for quantification of potential amounts payable under the Agreements.

Beginning in 2006, all long-term incentive awards contain a "double trigger" vesting provision, which provides for accelerated vesting only if outstanding awards are not assumed by an acquirer or the Named Executive is terminated without cause within 24 months of a change in control. The double trigger, which is viewed as a corporate governance "best practice", ensures that the Named Executives do not receive accelerated benefits unless they are adversely affected by the change in control.

Other than the Agreements described above, we have not entered into any other severance agreements or employment agreements with any Named Executives except that in December 2006, TEP entered into an employment agreement for a term of six months with Dennis R. Nelson in conjunction with the termination of his Change in Control Agreement. At the time the Company and Mr. Nelson entered into such agreement, Mr. Nelson announced his intention to retire in June 2007. The employment agreement with Mr. Nelson, Senior Vice President, Utility Services, terminates upon his retirement on June 1, 2007. The employment agreement provides that TEP will pay Mr. Nelson a fixed salary of not less than his current annual salary of $295,000, subject to periodic review and increase by the Board of Directors, and for Mr. Nelson's continued participation in TEP's compensation and employee benefit plans. The agreement provides that TEP will pay Mr. Nelson a severance payment in the event that TEP terminates Mr. Nelson's employment for reasons other than cause, disability or death, or, if Mr. Nelson terminates his employment following (1) a material reduction of his responsibilities; (2) a material reduction of compensation; (3) relocation or reassignment beyond 50 miles from the location that he works currently; or (4) certain liquidation, dissolution, consolidation or merger transactions involving the company. Severance is to be paid in a lump sum cash payment and the amount will equal any annual target bonus owing but unpaid for 2006, $300,000 (less any amount paid in respect of the 2006 target bonus), and a prorated annual target bonus for the year of the termination. In addition, the agreement provides that Mr. Nelson will receive service credit for eligibility and benefits purposes until June 1, 2007 and will be entitled to participate in the Company retiree medical plan regardless of the actual date his employment is terminated.

The Compensation Committee and the Board are currently in the process of evaluating future alternatives associated with change-in-control protection that may be offered to Named Executives who have not been party to a Change in Control Agreement.

Retirement and Other Benefits

Benefits Generally

The Company offers retirement and other core benefits to its employees, including executive officers, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The benefits are the same for all employees and executive officers and include medical and dental coverage, disability insurance and life insurance. In addition, the Tucson Electric Power Company 401(k) Plan and the Retirement Plan provide a reasonable level of retirement income reflecting employees' careers with the Company. All employees, including executive officers, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each executive officer. To the extent that any officer's retirement benefit exceeds Internal Revenue Service ("IRS") limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the Excess Benefits Plan and the DCP. These plans provide only the difference between the calculated benefits and the IRS limits.

Tucson Electric Power Company Excess Benefits Plan

The Retirement Plan is subject to Code limitations on the amount of compensation that can be taken into account and on the amount of benefits that can be provided. The Excess Benefits Plan provides retirement benefits to officers in addition to the maximum amount of benefits payable under the Retirement Plan. The Excess Benefits Plan retirement benefit is calculated generally using the same pension formula as the Retirement Plan formula but with some modifications. Compensation for purposes of the Excess Benefits Plan is determined without regard to IRS limits on compensation and by including voluntary salary reductions to the DCP, and any annual incentive payment received under the PEP. The retirement benefit payable from the Excess Benefits Plan is reduced by the benefit payable to that person from the Retirement Plan.

Benefits under the Excess Benefits Plan are provided to officers but, with limited exceptions, are not generally available to other employees. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry.

UniSource Energy Corporation Management and Directors Deferred Compensation Plan

The DCP allows participants (which include directors, officers and managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis. A participant may elect to defer a percentage of his salary or any bonus up to 100%.

The DCP provides Named Executives and other participants with the opportunity to defer a portion of their base salary and bonus into various investment alternatives, including UniSource Energy stock units. Additionally, we credit the DCP accounts of executives participating in our 401(k) Plan with the additional amount of UniSource Energy matching contributions that the participant would have been entitled to under our 401(k) Plan but for certain Code limits. We believe this plan assists with our attraction and retention objectives since it provides an industry-competitive and tax-efficient benefit to our executives. The DCP is not funded by the Company and participants have an unsecured contractual commitment by the Company to pay amounts owed under the DCP.

STOCK OWNERSHIP POLICY

To further support our objective of aligning management and shareholder interests, we adopted a formal stock ownership policy, which encourages all officers to accumulate a substantial ownership stake in Company shares. The policy has the following key features:

- Participants are encouraged to accumulate Company shares with a target value of a multiple of their base salary, ranging from one times base salary for Vice Presidents to five times for our CEO. The Named Executives other than the CEO have a target value equal to three times their base salary.

- If a participant has not yet reached the applicable target ownership requirement, he is expected to retain a portion of the net after-tax shares acquired from any stock option exercise, vesting of restricted stock or payments related to the performance share program. The applicable retention rates are 100% for the CEO, 50% for the other Named Executives and 25% for the other Vice Presidents.

- Unexercised stock options, unvested stock options and unearned performance shares do not count towards meeting the ownership guidelines.

Annually, management provides a report to the Compensation Committee regarding the number and value of the shares held by each officer subject to the guidelines. As of December 31, 2006, all executives who were hired before 2005, including the CEO, have achieved their target ownership level; five officers appointed subsequently are making progress toward meeting the guidelines.

IMPACT OF REGULATORY REQUIREMENTS

Under Section 162(m) of the Code, certain items of compensation paid to the CEO and to each of the other Named Executives in excess of $1,000,000 annually are not deductible for federal income tax purposes unless the compensation is awarded under a performance-based plan approved by the shareholders. With respect to performance-based compensation, Section 162(m) of the Code requires that performance metrics be set within 90 days of the commencement of the performance period. Accordingly, the Compensation Committee schedules its meetings so that the incentive-based compensation programs designed to provide performance-based compensation, within the meaning of Code section 162(m), are approved during the first quarter of the year. To the extent that the Company complies with the performance-based compensation provision of Section 162(m), the awards granted to the CEO and other Named Executives are tax deductible by the Company.

The Compensation Committee believes that it is in the best interest of the Company to receive maximum tax deductibility for compensation paid to the Named Executives under Section 162(m) of the Code, although to maintain flexibility in compensating Named Executives in a manner designed to promote varying corporate goals, the Compensation Committee may award compensation that is not fully deductible under certain circumstances. The Company's compensation plans reflect the Compensation Committee's intent and general practice to pay compensation that the Company can deduct for purposes of federal income tax. Executive compensation decisions, however, are multifaceted. The Compensation Committee reserves the right to pay amounts that are not tax deductible to meet the design goals of our executive compensation program.

The Compensation Committee also considers other financial implications when developing and implementing the Company's compensation program, including accounting costs, cash flow impact and potential share dilution.

EXHIBIT
S-16
Admitted

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-11 Refer to Mr. Dukes' rebuttal at page 12.

a. Provide a copy of the Deferral Compensation Plan.

b. Does the Deferral Compensation Plan allow officers, directors and managers to defer a higher percentage of their compensation than is permissible through the Company's 401k plan? If not, explain fully.

c. What percentage of compensation can officers, directors and managers defer under the Deferred Compensation Plan?

d. What percentage of compensation can officers, directors and managers defer under the 401k plan?

e. Is the Deferral Compensation Plan a qualified plan under the Internal Revenue Code and Treasury Regulations? If not, explain fully. If so, please identify the provisions of the Code and Regs under which it qualifies.

f. Is the Deferral Compensation Plan a discriminatory plan, in that it is limited only to directors, officers and managers?

g. Please describe the eligibility for the Deferral Compensation Plan.

RESPONSE:

a. Please see STF 22-11, Bates Nos. UNSG(0463)06221 to UNSG(0463)06255, on the enclosed CD for a copy of the Deferred Compensation Plan Document.

b. The Deferred Compensation Plan does allow eligible officers, directors and managers to defer a higher percentage of their compensation than is permissible through the Company's 401(k) Plan.

c. Subject to the minimum deferral provisions, the amount of Compensation which an Eligible Employee selected in accordance with Section 2.1 or Director may elect to defer is as follows:

(1) Any percentage of Salary up to 100%; and/or

(2) Any percentage or dollar amount of Bonus up to 100%;

d. Eligible TEP officers and managers may defer up to 25% of salary and bonus under the 401(k) Plan. Eligible UNS Gas managers may defer up to 50% of salary and bonus under the 401(k) Plan. In both instances referenced above, deferrals may not exceed the annual IRS Code deferral limits (in 2005 the annual limit for participant elected deferrals was $14,000.) All participants age 50 and over are eligible to contribute Catch-up Contributions up to an additional 50% of salary and bonus, not to exceed the annual IRS Code limit (in 2005 the annual limit for Catch-up Contributions was $4,000.) Directors are ineligible to defer compensation under the 401(k) Plan.

e. The Deferred Compensation Plan is a non-qualified plan under the Internal Revenue Code.

f. The Deferred Compensation Plan is a discriminatory plan, in that it is limited only to eligible directors, officers and managers.

g. See attached Plan Document provided in part (a) above for description of eligibility for the Deferred Compensation Plan.

RESPONDENT: HR Services Group

WITNESS: Dallas Dukes

UNISOURCE ENERGY CORPORATION
MANAGEMENT AND DIRECTORS DEFERRED COMPENSATION PLAN
(As Amended and Restated Effective January 1, 2001)

UNISOURCE ENERGY CORPORATION
MANAGEMENT AND DIRECTORS
DEFERRED COMPENSATION PLAN
(As Amended and Restated Effective January 1, 2001)

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UNISOURCE ENERGY CORPORATION
MANAGEMENT AND DIRECTORS DEFERRED COMPENSATION PLAN
(As Amended and Restated Effective January 1, 2001)

WHEREAS, UniSource Energy Corporation (the "Company") and certain of its affiliates maintain the UniSource Energy Corporation Management and Directors Deferred Compensation Plan, as amended (the "Plan");

WHEREAS, the Company and its participating affiliates maintain the Plan to provide for the future payment of compensation deferred by Participants under the Plan for the purpose of (i) promoting ownership of the Common Stock of the Company, and (ii) providing Participants with supplemental retirement income benefits; and

WHEREAS, it is desirable to amend and restate the Plan as set forth herein.

NOW, THEREFORE, the Plan is hereby amended in its entirety, effective as of January 1, 2001, as follows:

ARTICLE I
TITLE AND DEFINITIONS

1.1 - <u>Title</u>.

This Plan shall be known as the UniSource Energy Corporation Management and Directors Deferred Compensation Plan.

1.2 - <u>Definitions</u>.

Whenever the following words and phrases are used in this Plan, with the first letter capitalized, they shall have the meanings specified below.

"Account" or "Accounts" shall mean a Participant's Deferral Account and/or Stock Account.

"Beneficiary" or "Beneficiaries" shall mean the person or persons, including a trustee, personal representative or other fiduciary, last designated in writing by a Participant in accordance with procedures established by the Committee to receive the benefits specified hereunder in the event of the Participant's death. No beneficiary designation shall become effective until it is filed with the Committee, and no beneficiary designation of someone other than the Participant's spouse shall be effective unless such designation is consented to by the Participant's spouse on a form provided by and in accordance with the procedures established by the Committee. If there is no Beneficiary designation in effect, or if there is no surviving designated Beneficiary, then the Participant's surviving spouse shall be the Beneficiary. If there is no surviving spouse to receive any benefits payable in accordance with the preceding sentence, the duly appointed and currently acting personal representative of the participant's estate (which shall include either the Participant's probate estate or living trust) shall be the Beneficiary. In any case where there is no such personal representative of the Participant's estate duly appointed and acting in that capacity within 90 days after the Participant's death (or such extended period as the Committee determines is reasonably necessary to allow such personal representative to be appointed, but not to exceed 180 days after the Participant's death), then Beneficiary shall mean the person or persons who can verify by affidavit or court order to the satisfaction of the Committee that they are legally entitled to receive the benefits specified hereunder. In the event any amount is payable under the Plan to a minor, payment shall not be made to the minor, but instead be paid (a) to that person's living parent(s) to act as custodian, (b) if that person's parents are then divorced, and one parent is the sole custodial parent, to such custodial parent, or (c) if no parent of that person is then living, to a custodian selected by the Committee to hold the funds for the minor under the Uniform Transfers or Gifts to Minors Act in effect in the jurisdiction in which the minor resides. If no parent is living and the Committee decides not to select another custodian to hold the funds for the minor, then payment shall be made to the duly appointed and currently acting guardian of the estate for the minor or, if no guardian of the estate for the minor is duly appointed and currently acting within 60 days after the date the amount becomes payable, payment shall be deposited with the court having jurisdiction over the estate of the minor.

"Board of Directors" or "Board" shall mean the Board of Directors of the Company.

"Bonus" shall mean any annual cash incentive compensation payable to a Participant by a Participating Affiliate in addition to the Participant's Salary.

"Code" shall mean the Internal Revenue Code of 1986, as amended.

"Committee" shall mean the Compensation Committee of the Board, which shall administer the Plan in accordance with Article VIII.

"Common Stock" shall mean the common stock, without par value, of UniSource Energy Corporation, subject to adjustment pursuant to Section 6.1 of the Plan.

"Company" shall mean UniSource Energy Corporation, and any successor corporation.

"Compensation" shall mean the Salary and Bonus that the Participant is entitled to for services rendered to a Participating Affiliate.

"Deferral Account" shall mean the bookkeeping account maintained by the Committee for each Participant that is credited with amounts equal to (1) the portion of the Participant's Salary that he or she elects to defer and invest in the manner described in Section 3.2, (2) the portion of the Participant's Bonus that he or she elects to defer and invest in the manner described in Section 3.2, (3) the portion of the Participant's Initial 401(k) Benefit and/or Excess 401(k) Benefits that he or she elects to have credited to such account in accordance with Section 3.3, and (4) earnings or losses pursuant to Section 4.1.

"Deferred Share" shall mean a non-voting unit of measurement, which is deemed solely for bookkeeping purposes under this Plan to be equivalent to one outstanding share of Common Stock (subject to Section 6.1).

"Director" shall mean any individual who is serving as a non-emeritus member of the Board and who is not an employee of the Company or one of its Subsidiaries.

"Disability" shall mean a mental or physical disability, which the Committee determines, based upon competent medical advice, has rendered the Participant incapable of performing substantial services for the Company or a Subsidiary.

"Dividend Equivalent" shall mean the amount of cash dividends or other cash distributions paid by the Company on that number of shares of Common Stock equal to the number of Deferred Shares credited to a Participant's Stock Account as of the applicable record date for the dividend or other distribution, which amount shall be credited in the form of additional Deferred Shares to the Participant's Stock Account, as provided in Section 4.2(d).

"Eligible Employee" shall mean any Officer or salaried key employee of a Participating Affiliate.

"Employer" means the Participating Affiliate that employed the Participant: (1) with respect to deferred Compensation (and earnings thereon), at the time the Participant deferred the related Compensation; and (2) with respect to Initial 401(k) Benefits (and earnings thereon) and Excess 401(k) Benefits (and earnings thereon), at the time the related Initial or Excess 401(k) Benefits, as applicable, were credited to the Participant's Account.

"ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended.

"Excess Plan" means the Tucson Electric Power Company Excess Benefit Plan, as amended from time to time.

"Excess 401(k) Benefit" means a Participant's benefit, if any, provided under Section 3.3(b) for a 401(k) Plan Year.

"Exchange Act" shall mean the Securities Exchange Act of 1934, as amended from time to time.

"Fair Market Value" shall mean on any date the closing price of the Common Stock on the Composite Tape, as published in the Western Edition of The Wall Street Journal, of the principal securities exchange or market on which the Common Stock is so listed, admitted to trade, or quoted on such date, or, if there is no trading of (or no available closing price of) the Common Stock on such date, then the closing price of the Common Stock as quoted on such Composite Tape on the next preceding date on which there was trading in such shares. If the Common Stock is not so listed, admitted or quoted, the Committee may designate such other exchange, market or source of data as it deems appropriate for determining such value for purposes of this Plan.

"401(k) Plan" shall mean the Tucson Electric Power Company 401(k) Plan, as amended (formerly the Tucson Electric Power Company Triple Investment Plan for Salaried Employees).

"401(k) Plan Year" shall mean a "Plan Year" under and as such term is defined in the 401(k) Plan.

"Fund" or "Funds" shall mean one or more of the investment funds or portfolios selected by the Committee pursuant to Section 3.2(b).

"Initial 401(k) Benefit" means a Participant's benefit, if any, provided under Section 3.3(a).

"Money Market Fund" shall mean a fictional fund, the deemed earnings or losses of which are measured with reference to one or more commercially available money market funds selected by the Committee.

"Officer" shall mean the President, any Senior Vice President, and any Vice President of the Company.

"Participant" shall mean (1) any Eligible Employee who is selected for participation in the Plan and who elects to defer Compensation in accordance with Section 3.1, (2) any Director who elects to defer Compensation in accordance with Section 3.1, or (3) any Eligible Employee who is credited with amounts in respect of Initial 401(k) Benefits and/or Excess 401(k) Benefits in accordance with Section 3.3.

"Participating Affiliate" means the Company or a Subsidiary that elects to adopt this Plan for the benefit of its employees. "Participating Affiliates" means, collectively, the Company and such Subsidiaries that have elected to adopt this Plan.

"Plan" shall mean this UniSource Energy Corporation Management and Directors Deferred Compensation Plan set forth herein, now in effect, or as amended from time to time.

"Plan Year" shall mean the 12 consecutive month period beginning January 1 each year.

"Retirement" shall mean the Participant has (1) attained his or her Early Retirement Age or Normal Retirement Age, as such terms are defined in the Tucson Electric Power Company Salaried Employees Retirement Plan; or (2) retired from the Board of Directors upon or after attaining age 62.

"Salary" shall mean all cash salary, fees (including Director's fees), and similar payments (other than Bonuses) paid to a Participant for services rendered to a Participating Affiliate before reduction on account of: (1) any withholding such as income taxes (but excluding social security and health insurance taxes), and (2) any deferrals under this Plan.

"Stock Account" shall mean a bookkeeping account maintained by the Committee for each Participant that is credited with any Deferred Shares and Dividend Equivalents with respect to such Deferred Shares.

"Subsidiary" shall mean each corporation, which is a member of a controlled group of corporations (within the meaning of Section 414(b) of the Code) of which the Company is a component member.

"Termination Date" shall mean the date that the Participant's employment or services with the Company and its Subsidiaries terminates for any reason.

"Trust" means a grantor trust maintained under the terms of the related Trust Agreement.

"Trust Agreement" means a trust agreement entered into by and between a Participating Affiliate and the related Trustee with respect to this Plan, as amended from time to time.

"Trustee" means the entity, which has entered into the related Trust Agreement as trustee of the Trust thereunder, and any duly appointed successor.

ARTICLE II
PARTICIPATION

2.1 - <u>Participation</u>.

The Committee shall select from the class of Eligible Employees those particular Eligible Employees who will be eligible to defer all or a portion of their Compensation in accordance with Section 3.1. Notwithstanding anything else contained in this Plan to the contrary, the Committee may, at any time and in its sole discretion, terminate the ability of an Eligible Employee, Director, or a Participant to defer additional amounts under Section 3.1.

Each Eligible Employee who had a Transferable Amount (as such term is defined in the Excess Plan) under the Excess Plan as of the close of business on February 26, 1999 shall participate in Section 3.3(a). Each Eligible Employee who is then participant in the 401(k) Plan shall be eligible to participate in Section 3.3(b) with respect to each 401(k) Plan Year commencing on or after January 1, 1999, provided (i) that the Eligible Employee's Compensation (as such term is defined in the 401(k) Plan) for such 401(k) Plan Year exceeds the limit applicable to such 401(k) Plan Year under Code Section 401(a)(17), and (ii) that the Eligible Employee has made the maximum Salary Deferral Contributions (as such term is defined in the 401(k) Plan) permitted under the 401(k) Plan for such 401(k) Plan Year.

Notwithstanding anything else contained herein to the contrary, the Committee shall limit the class of persons selected in accordance with the first paragraph of this Section 2.1, or otherwise eligible to participate in Section 3.3, to a select group of management or highly compensated employees, as set forth in Sections 201, 301 and 401 of ERISA. In order to accomplish the foregoing, the Committee may terminate the deferrals of any one or more individuals in accordance with the first paragraph of this Section 2.1 and/or provide that one or more Eligible Employees otherwise eligible to participate in Section 3.3 shall accrue no additional benefits thereunder (except earnings or losses on amounts previously credited).

ARTICLE III
DEFERRAL ELECTIONS

3.1 - Elections to Defer Compensation.

(a) General Rule. Subject to the minimum deferral provisions in paragraph (b) below, the amount of Compensation which an Eligible Employee selected in accordance with Section 2.1 or Director may elect to defer is as follows:

(1) Any percentage of Salary up to 100%; and/or

(2) Any percentage or dollar amount of Bonus up to 100%;

provided, however, that no election shall be effective to reduce the Compensation payable to an Eligible Employee for a calendar year to an amount which is less than the amount that the Company or a Subsidiary is required to withhold from such Eligible Employee or Director's Compensation for such calendar year for purposes of federal, state and local (if any) income tax, employment tax (including without limitation Federal Insurance Contributions Act (FICA) tax), and other tax withholdings.

(b) Minimum Deferrals. For each year during which an Eligible Employee or Director is a Participant, the minimum amount that may be elected under Section 3.1(a)(1) is $3,500.

(c) Initial Election. An Eligible Employee selected in accordance with Section 2.1 or Director may elect to participate in the Plan by filing an initial election with the Committee, on a form and in a manner prescribed by the Committee, no later than the 30th day following his or her employment or service commencement date. Such election shall be effective with respect to Salary earned in the first pay period beginning after the filing of such election and, if the election is filed on or before October 15 of a Plan Year, to the Bonus payable for the Plan Year in which the election is filed.

(d) Duration of Salary Deferral Election. Any Salary deferral election made under this Section 3.1 shall remain in effect, notwithstanding any change in the Participant's Salary, until changed or terminated in accordance with the terms of this paragraph (d). Subject to the limitations of Section 3.1(a) and the minimum deferral requirements of Section 3.1(b), a Participant may increase, decrease or terminate his or her Salary deferral election, effective for Salary earned during pay periods beginning after any January 1, by filing a new election, in accordance with the terms of this Section 3.1 and on a form and in a manner prescribed by the Committee, with the Committee on or before the preceding December 15.

(e) Duration of Bonus Deferral Election. Any Bonus deferral election made under this Section 3.1 shall be irrevocable and shall apply only to the Bonus payable with respect to services performed during the Plan Year in which the election is made. For each subsequent Plan Year, an Eligible Employee may make a new election, subject to the limitations set forth in this Section 3.1, to defer a percentage or dollar amount of his or her Bonus earned in such Plan Year. Such election shall be on forms provided by the Committee and shall be made on or before the October 15 of the Plan Year in which such Bonus is earned.

(f) Subsequent Elections. Any Eligible Employee selected in accordance with Section 2.1 or Director who fails to make an initial election to defer Compensation in accordance with Section 3.1(c), or any Eligible Employee selected in accordance with Section 2.1 or Director who elects to defer Compensation in accordance with Section 3.1(c) and who later elects to terminate such deferrals in accordance with Section 3.1(d), may subsequently become (or may again become) a Participant (provided that he or she is then still eligible to participate in the Plan in accordance with Section 2.1), by filing an election, on a form and in a manner prescribed by the Committee, to defer Compensation as described in paragraph (a) above. An election to defer Salary must be filed on or before December 15 and will be effective for Salary earned during pay periods beginning after the following January 1; an election to defer a Bonus must be filed on or before October 15 and will be effective for the Bonus earned with respect to services performed in the Plan Year in which the election is made.

(g) Life Insurance Applications. In connection with an Eligible Employee's or Director's deferral election (or as a condition to the continued effect of such an election), the Committee may require the Eligible Employee or Director to complete and return a life insurance application on a form provided by the Committee. The Committee may establish rules and a deadline for the return and filing of such application. The Committee, in its sole discretion, may void the Eligible Employee's or Director's deferral election if the application is not timely returned or filed.

3.2 - Manner of Deferral; Investment Elections for Deferral Account.

(a) At the time of making the deferral elections described in Section 3.1, the Participant shall specify, on a form and in a manner prescribed by the Committee, whether the Compensation he or she elects to defer is to be deferred in the form of (i) cash and credited to the Participant's Deferral Account in accordance with Section 4.1, and/or (ii) Deferred Shares and credited to the Participant's Stock Account in accordance with Section 4.2. If the Participant does not make such an election (1) the Participant shall be deemed to have elected a 100% contribution to his or her Stock Account unless the Participant had previously made such an election, or (2) if the Participant had previously made such an election, the Participant's Compensation deferrals shall be allocated between his or her Deferral Account and/or Stock Account in accordance with

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the Participant's most recent election. Notwithstanding anything else contained herein to the contrary, amounts deferred by an Officer or Director pursuant to a deferral election entered into before January 1, 1997 shall remain credited to the Participant's Stock Account in the form of Deferred Shares.

(b) The Committee shall select, from time to time, one or more investment funds or indices to be used, together with the Money Market Fund, as the Funds for purposes of determining the amount of earnings (or losses) to be credited to Participants' Deferral Account. The Committee shall notify each Participant of the investment funds and/or indices selected as the Funds. The Committee may, at any time and without notice, change the number, types and/or particular Funds offered; provided, however, that for a period of 12 months following a "change in control" of the Company (as such term is used in the Company's 1994 Omnibus Stock and Incentive Plan, as amended), the Committee may not eliminate any Fund that was offered immediately preceding such event or change the definition of the Money Market Fund.

(c) At the time of making any Salary and/or Bonus deferral elections described in Section 3.1 for a Plan Year, the Participant shall designate, on a form and in a manner prescribed by the Committee, which of the Funds the Participant's Deferral Account will be deemed to be invested in for purposes of determining the amount of earnings to be credited to his or her Deferral Account. If a Participant fails to designate a Fund (1) the Participant shall be deemed to have elected the Money Market Fund unless the Participant had previously made a Fund election, or (2) if the Participant had previously made a Fund election, the Participant's most recent Fund election shall apply.

(d) In making the designation pursuant to Section 3.2(c), the Participant must specify, in whole numbers, the percentage of his or her Deferral Account which shall be deemed to be invested in one or more of the Funds, which percentage (unless otherwise provided by the Committee) must be at least 10% for each Fund selected. Effective as of the end of any calendar month, a Participant may change the designation made under Section 3.2(c) (subject to the other limitations of this Section 3.2(d)) and/or transfer an amount deemed to be invested in one Fund to another Fund (subject to such rules as the Committee may adopt) by filing an election with the Committee, on a form and in a manner prescribed by the Committee, prior to any deadline that may be established by the Committee and in no event later than the last day of such month. The Committee may permit more frequent than monthly elections and may establish rules regarding the timing and effectiveness of such elections.

(e) Although the Participant may designate the Fund or Funds in which his or her Deferral Account will be deemed to be invested, neither the Committee, any Participating Affiliate, nor any other entity shall have any obligation to actually invest the amounts deferred under this Plan in any particular investment. In the event that a Participating Affiliate invests any funds in any commercial investment funds used as Funds under this Plan, title to and beneficial ownership of such invested funds shall at all times remain that of the Participating Affiliate and no Participant, Beneficiary or any other person shall have any interest whatsoever in such invested funds.

3.3 - **401(k) Plan Benefits**.

(a) A Participant's Initial 401(k) Benefit shall equal the Participant's Transferable Amount (as such term is defined in the Excess Plan) under the Excess Plan (if any) as of the close of business on February 26, 1999. Each Participant may elect prior to the close of business on March 15, 1999, on a form and in a manner prescribed by the Committee, to have his or her Initial 401(k) Benefit credited (i) in the form of cash to his or her Deferral Account, and/or (ii) in the form of Deferred Shares to his or her Stock Account; otherwise, the amount will be credited in the form of Deferred Shares to the Participant's Stock Account. If a Participant elects to have all or a portion of his or her Initial 401(k) Benefits credited to his or her Deferral Account, the Participant shall also designate on such election, in 10% increments, which types of investment funds or portfolios from those then offered under the Plan his or her portion of the Initial 401(k) Benefit will initially be deemed to be invested for purposes of determining the amount of earnings or losses to be credited thereon.

(b) A Participant's Excess 401(k) Benefit for a 401(k) Plan Year shall equal the positive difference, if any, between (i) the total Company Matching Contribution (as such term is defined in the 401(k) Plan) that would have been allocated to such Participant's account under the 401(k) Plan for that 401(k) Plan Year if the limit applicable to such year under Code Section 401(a)(17) did not apply (but taking into account all other applicable limits under the Code and the 401(k) Plan), less (ii) the actual Company Matching Contribution allocated to such Participant's account under the 401(k) Plan for that 401(k) Plan Year. Each Participant may elect prior to the end of a 401(k) Plan Year, on a form and in a manner prescribed by the Committee, to have his or her Excess 401(k) Benefits credited (i) in the form of cash to his or her Deferral Account, and/or (ii) in the form of Deferred Shares to his or her Stock Account; otherwise, the amount will be credited in the form of Deferred Shares to the Participant's Stock Account. If a Participant elects to have all or a portion of his or her Excess 401(k) Benefits credited to his or her Deferral Account, the Participant shall also designate on such election, in 10% increments, the Funds in which his or her Excess 401(k) Benefits will initially be deemed to be invested for purposes of determining the amount of earnings or losses to be credited thereon. A Participant's election shall continue in effect for all subsequent 401(k) Plan Years until a new election, on a form and filed in the manner prescribed by the Committee, is received by the Committee; provided that any new election shall not affect any Excess 401(k) Benefits credited or to be credited with respect to a 401(k) Plan Year prior to the year in which such election is received by the Committee.

(c) Separate subaccounts shall be established by the Committee under each Participant's Deferral Account and Stock Account to separately account for (i) amounts attributable to the Participant's Initial 401(k) Benefit and Excess 401(k) Benefits (if any), (ii) amounts payable under different distribution options elected by the Participant ("distribution subaccounts"), (iii) in the case of the Participant's Deferral Account, portions of such account corresponding to the Fund(s) elected by the Participant pursuant to Section 3.2(c) ("investment subaccounts"), and (iv) amounts for which different Participating Affiliates are liable for payment.

3.4 - <u>In-Service Distribution Elections</u>.

Effective with deferral elections received by a Participating Affiliate after July 1, 2000, at the time of making the election to defer Salary and/or Bonus for a Plan Year pursuant to Section 3.1, the Participant shall designate, on a form and in a manner prescribed by the Committee, the time at which the Compensation deferred by the Participant pursuant to such election (adjusted for earnings and losses thereon) will be paid. A Participant may make only one payment election for all Compensation deferred pursuant to that election and a Participant may not make separate Salary or Bonus payment elections. A payment election pursuant to this Section 3.4 shall apply only to the Compensation deferred by the Participant for the first Plan Year with respect to which the related deferral election is effective (even though the deferral election may continue in effect with respect to Salary earned in subsequent Plan Years pursuant to Section 3.1(d)). A Participant must make a new election pursuant to this Section 3.4, by the deferral election deadline for the related Plan Year, with respect to each Plan Year for which the Participant wants to elect an in-service distribution.

The Participant may choose either one of the following payment dates (or, if installments are elected, payment commencement dates) for the payment of his or her deferrals (adjusted for earnings and losses thereon) pursuant to an election:

(1) On or as soon as administratively practical after the Participant's Termination Date, or

(2) On or as soon as administratively practical after the earlier of (a) the Participant's Termination Date or (b) any date selected by the Participant which is at least two years following the end of the Plan Year for which the Compensation is deferred (an "in-service distribution date").

If the Participant does not make such an election, the Participant shall be deemed to have elected payment on or as soon as administratively practical after the Participant's Termination Date..

If the Participant elects an in-service distribution date, the Participant's election shall also indicate whether the in-service distribution shall be in the form of:

(1) A lump sum payment;

(2) Substantially equal quarterly installments over five years;

(3) Substantially equal quarterly installments over a period of ten years; or

(4) Substantially equal quarterly installments over a period of fifteen years.

If the Participant elects an in-service distribution date, but does not specify a payment form, the Participant shall be deemed to have elected a lump sum payment. The Participant's form of payment election shall have no effect if the payment of the Participant's benefits is triggered by the Participant's Termination Date.

The Committee, in its discretion, may permit an election of monthly installment payments and may permit elections of other payout periods, provided that no payout period shall be more than fifteen years. A Participant's election under this Section 3.4 shall have no effect on the payment of the Participant's Excess 401(k) Benefit (if any) for that year.

Subject to the following provisions in this paragraph and Sections 7.2 and 7.3, no changes may be made to a payment election under this Section 3.4 after such election is filed. If a Participant elects an in-service distribution date with respect to his or her deferrals for a Plan Year, the Participant may subsequently change his or her in-service distribution date with respect to such deferrals to a later date (but not an earlier date) or the Participant may change his or her election to a Termination Date distribution; provided (1) that such a change election must be filed with the Committee at least one year prior to the original in-service distribution date, (2) that such a change election must be made on a form and in a manner prescribed by the Committee, and (3) that a Participant may make only one such change with respect to his or her deferrals for a Plan Year. A Participant may change his or her form of in-service payment election (for example, from a lump sum to installments), provided that his or her election is filed with the Committee, on a form and in a manner prescribed by the Committee, at least one year prior to his or her in-service distribution date. If a Participant makes more than one such change applicable to a Plan Year's deferrals, the Committee may rely on the most recent election it received at least one year prior to the Participant's in-service distribution date.

3.5 - **Form of Payment Election.**

Each Participant shall designate, on a form and in a manner prescribed by the Committee, the manner in which the Participant's Plan benefits shall be paid in the event the Participant's termination of employment or service with the Company and its Subsidiaries is due to the Participant's Retirement or Disability. Each Participant may elect one of the following payment forms:

(1) A lump sum payment;

(2) Substantially equal quarterly installments over five years;

(3) Substantially equal quarterly installments over a period of ten years; or

(4) Substantially equal quarterly installments over a period of fifteen years.

If a Participant does not specify a payment form, the Participant shall be deemed to have elected (1) if the Participant's Termination Date is on or before December 31, 2001, substantially equal quarterly installments over a period of fifteen years, or (2) if the Participant's Termination Date is after December 31, 2001, a lump sum payment. A Participant's election under this Section 3.5 shall apply to all of a Participant's deferrals regardless of the Plan Year in which they were made.

The Committee, in its discretion, may permit an election of monthly installment payments and may permit elections of other payout periods, provided that no payout period shall be more than fifteen years.

Subject to the following provisions in this paragraph and Sections 7.2 and 7.3, no changes may be made to a payment election under this Section 3.5 after such election is filed. A Participant may change his or her form of Retirement or Disability payment election (for example, from a lump sum to installments), provided that his or her election is filed with the Committee, on a form and in a manner prescribed by the Committee, at least one year prior to his or her Termination Date. If a Participant makes more than one such change, the Committee may rely on the most recent election it received at least one year prior to the Participant's Termination Date.

ARTICLE IV
ACCOUNTS

4.1 - <u>Deferral Account</u>.

The Committee shall establish and maintain a Deferral Account for each Participant under the Plan. A Participant's Deferral Account shall be credited as follows:

(a) As soon as administratively practical after the date on which the deferred Salary would have otherwise been paid to the Participant, the Committee shall credit the Participant's Deferral Account with an amount equal to the Salary that the Participant elected to defer and have credited to his or her Deferral Account under Section 3.2.

(b) As soon as administratively practical after the date on which the deferred Bonus would have otherwise been paid to the Participant, the Committee shall credit the Participant's Deferral Account with an amount equal to the Bonus that the Participant elected to defer and have credited to his or her Deferral Account under Section 3.2.

(c) On a date selected by the Committee in the first quarter of each calendar year, the Committee shall credit the Participant's Deferral Account with the amount of the Participant's Excess 401(k) Benefit for the immediately preceding 401(k) Plan Year (if any) that the Participant elected to have credited to his or her Deferral Account. In addition, as of the close of business on February 26, 1999, the Committee shall credit the Participant's Deferral Account with the amount of the Participant's Initial 401(k) Benefit (if any) that the Participant elected to have credited to his or her Deferral Account.

(d) Each credit to a Participant's Deferral Account shall be to the distribution subaccount and/or investment subaccount, as applicable, corresponding to the Participant's distribution and Fund election(s). Each investment subaccount of a Participant's Deferral Account shall be credited on a daily basis with deemed earnings or losses, the amount of such earnings or losses determined based on the amount credited to that subaccount at the start of business on that day and the amount that an investment of an equal amount in the corresponding Fund would earn (or lose) for that day. The Committee may adopt such other earnings crediting rules and procedures (including different timing rules for crediting earnings) as it deems advisable, provided that deemed earnings are credited at least on a monthly basis based on the experience of the corresponding Fund and based on account balances.

(e) The Committee may provide that amounts shall be credited more frequently than the date or dates otherwise provided in this Section 4.1 or Section 4.2.

(f) A Participant's Deferral Account shall be reduced by any distributions, payments, forfeitures, or withdrawals from that Account.

4.2 - Stock Account.

(a) The Committee shall establish and maintain a Stock Account for each Participant who has elected under Section 3.2(a) to defer all or a portion of his or her Compensation in Deferred Shares.

(b) As soon as administratively practical after the date on which the deferred Salary and/or Bonus would have otherwise been paid to the Participant, the Committee shall credit the Participant's Stock Account with an amount equal to the Salary and/or Bonus deferred by the Participant that the Participant elected to defer and have credited to his or her Stock Account. A Participant's Stock Account shall be credited with a number of Deferred Shares determined by dividing the amount of Salary and/or Bonus deferred by the Participant to his or her Stock Account by the then current Fair Market Value of a share of Common Stock.

(c) On a date selected by the Committee in the first quarter of each calendar year, a Participant's Stock Account shall also be credited with a number of Deferred Shares determined by dividing: (i) the portion of the Participant's Excess 401(k) Benefit for the immediately preceding 401(k) Plan Year (if any) that is to be credited in the form of Deferred Shares in accordance with Section 3.3(b), by (ii) the Fair Market Value of a share of Common Stock as of such date of crediting. In addition, as of the close of business on February 26, 1999, a Participant's Stock Account shall also be credited with a number of Deferred Shares determined by dividing: (i) the portion of the Participant's Initial 401(k) Benefit (if any) that is to be credited in the form of Deferred Shares in accordance with Section 3.3(a), by (ii) the Fair Market Value of a share of Common Stock as of such date.

(d) As of the date on which the Company pays a dividend on its Common Stock (the "Crediting Date"), the Participant's Stock Account shall be credited with additional Deferred Shares equal in number to (i) the amount of the Dividend Equivalents representing cash dividends paid on that number of shares equal to the aggregate number of Deferred Shares in the

Participant's Stock Account at the start of business as of the relevant dividend record date, divided by (ii) the Fair Market Value of a share of Common Stock as of the Crediting Date.

(e) A Participant's Stock Account shall be a memorandum account on the books of a Participating Affiliate. The Deferred Shares credited to a Participant's Stock Account shall be used solely as a device for the determination of the number of shares of Common Stock to be eventually distributed to such Participant in accordance with this Plan. The Deferred Shares shall not be treated as property or as a trust fund of any kind. No Participant shall be entitled to any voting or other stockholder rights with respect to Deferred Shares granted or credited under this Plan. The number of Deferred Shares credited (and the Common Stock to which the Participant is entitled under this Plan) shall be subject to adjustment in accordance with Section 6.1 of this Plan.

(f) A Participant's Stock Account shall be reduced by the number of Deferred Shares with respect to which payment, distribution or a withdrawal is made, or which are forfeited.

ARTICLE V
VESTING

5.1 - <u>Deferral Account</u>.

A Participant's Deferral Account shall be 100% vested at all times.

5.2 - <u>Stock Account</u>.

A Participant's Stock Account shall be 100% vested at all times.

ARTICLE VI
ADJUSTMENTS TO AND TRANSFERS BETWEEN ACCOUNTS

6.1 - Adjustments in Case of Changes in Common Stock.

If any stock dividend, stock split, recapitalization, merger, consolidation, combination or other reorganization, exchange of shares, sale of all or substantially all of the assets of the Company, split-up, split-off, extraordinary redemption, liquidation or similar change in capitalization or any distribution to holders of the Company's Common Stock (other than cash dividends and cash distributions) shall occur, proportionate and equitable adjustments consistent with the effect of such event on stockholders generally (but without duplication of benefits if Dividend Equivalents are credited) shall be made in the number and type of shares of Common Stock or other securities, property and/or rights contemplated hereunder and of rights in respect of Deferred Shares and Stock Accounts credited under this Plan so as to preserve the benefits intended.

6.2 - Transfers Between Accounts.

Effective as of the end of any calendar month (or more frequently if the Committee so provides), a Participant may elect to have the Committee (1) reduce the number of any Deferred Shares allocated to his or her Stock Account and credit an amount (such amount equal to the Fair Market Value of the same number of shares of Common Stock as the number of Deferred Shares so reduced) to such Participant's Deferral Account, or (2) reduce the amount credited to his or her Deferred Account and credit such amount as Deferred Shares to his or her Stock Account (such number of Deferred Shares to be determined by dividing the cash amount deducted from the Participant's Deferral Account in the transfer by the then Fair Market Value of a share of Common Stock). Any such election shall be filed with the Committee, on a form and in a manner prescribed by the Committee, at least 30 days prior to the end of the calendar month (or such other time that the Committee may require). Unless otherwise provided by the Participant in accordance with such rules as the Committee may adopt (1) the amount transferred to a Participant's Deferral Account pursuant to this Section 6.2 shall be credited to such Deferral Account in accordance with the Participant's prior Fund election, and (2) any amount transferred from a Deferral Account to the Participant's Stock Account shall be pro rata from the Participant's Funds. Notwithstanding the foregoing, the Committee may establish alternative procedures for, and timing of, elective transfers with respect to any Participants who are subject to the short-swing profit provisions of Section 16 of the Exchange Act. Furthermore, notwithstanding anything else contained herein to the contrary, the portion of an Officer's or Director's Stock Account attributable to amounts deferred pursuant to a deferral election entered into before January 1, 1997 shall remain credited to the Participant's Stock Account in the form of Deferred Shares.

ARTICLE VII
DISTRIBUTIONS

7.1 - **Distribution of Deferred Compensation and Common Stock.**

(a) This Section 7.1 shall apply to Compensation deferred by Eligible Persons (other than Officers) after April 1, 1997, to Compensation deferred by Officers and Directors after December 31, 1997, and to amounts credited as or in respect of Initial 401(k) Benefits and/or Excess 401(k) Benefits. Any Compensation deferred pursuant to an election made by an Officer or Director with respect to Plan Years beginning prior to January 1, 1998 shall be paid in the manner and at the times required by Section 4.1 of the prior version of this Plan and the Officer or Director's related deferral election.

(b) If a Participant's in-service distribution date occurs prior to the Participant's Termination Date, then the portion of the Participant's Deferral Account that is subject to such in-service distribution election shall be paid to the Participant in cash and the Deferred Shares credited to the portion of his or her Stock Account that is subject to such in-service distribution election shall be distributed to the Participant in the form of an equivalent number of whole shares of Common Stock. Payment shall be made (or, if the Participant elected installments, installments shall commence) on or as soon as administratively practical after the relevant in-service distribution date in the form elected by the Participant pursuant to Section 3.4.

(c) If a Participant's employment or service with the Company and its Subsidiaries terminates by a reason other than Retirement or Disability, then, on or as soon as administratively practical after the Participant's Termination Date, the amount credited to his or her Deferral Account shall be paid to the Participant (or, in the case of his or her death, Beneficiary) in the form of a cash lump sum payment and the Deferred Shares credited to his or her Stock Account shall be distributed in the form of an equivalent number of whole shares of Common Stock. This Section 7.1(c) shall apply regardless of any distribution election made pursuant to Section 3.4 or 3.5 to the contrary. If the Participant is receiving an in-service distribution in the form of installment payments as of his or her Termination Date, then the remaining installments shall be cancelled and the remaining balance of the Participant's Accounts subject to such in-service distribution election shall be paid as part of the lump sum described above.

(d) If a Participant's employment or service with the Company and its Subsidiaries terminates by reason of Retirement or Disability, the amount credited to his or her Deferral Account shall be paid to the Participant in the form of cash and Deferred Shares credited to his or her Stock Account shall be distributed in the form of an equivalent number of whole shares of Common Stock. Such amounts shall be paid in the form elected by the Participant in accordance with Section 3.5. Payment shall be made (or installments commence) as soon as administratively practical after the Participant's Termination Date. If the Participant is receiving an in-service distribution in the form of installment payments as of his or her Termination Date and the relevant in-service distribution date occurred prior to the Participant's Termination Date, then this Section 7.1(d) shall have no effect on the continuing payment of the portion of his or her Accounts subject to that in-service distribution election.

(e) Notwithstanding the foregoing Sections 7.1(a) – (d) or any election under Section 3.4 or 3.5 to the contrary, in the event that the amount credited to the Participant's Accounts (or distribution subaccounts that become payable) as of the date his or her payments commence is less than $25,000, the applicable Participating Affiliate may, in its discretion, elect to pay the amount credited to the Participant's Deferral Account (or distribution subaccount, as applicable) to the Participant in the form of a cash lump sum payment and distribute the Deferred Shares credited to his or her Stock Account (or distribution subaccount, as applicable) in a lump sum in the form of an equivalent number of whole shares of Common Stock. A Participating Affiliate also may shorten any elected installment payment period to the extent necessary to produce installment payments of at least $1,000. In no event will any fractional shares be delivered. The Fair Market Value of any fractional Deferred Shares shall be paid in cash.

(f) The Participant's Deferral Account balance shall continue to be credited monthly with earnings pursuant to Section 4.1 of the Plan, and the Participant's Stock Account will continue to be credited with Dividend Equivalents pursuant to Section 4.2, until all amounts credited to his or her Accounts have been distributed.

(g) In the event that a former Participant dies while receiving installment payments under this Plan or with an installment payment election in effect under this Plan, the balance of the Participant's Accounts shall be paid to the Participant's Beneficiary, in the form of a lump sum payment, as soon as administratively practical.

(h) Notwithstanding anything herein to the contrary, if the Committee determines in good faith that there is a reasonable likelihood that any benefits paid to a Participant for a taxable year of the respective Participating Affiliate would not be deductible by the Participating Affiliate solely by reason of the limitation under Section 162(m) of the Code, then, to the extent reasonably deemed necessary by the Committee to ensure that the entire amount of any distribution to the Participant pursuant to this Plan is deductible, the Committee may defer all or any portion of a distribution under this Plan. The amounts so deferred shall be distributed to the Participant or his or her Beneficiary (in the event of the Participant's death) at the earliest possible date, as determined by the Committee in good faith, on which the deductibility of compensation paid or payable to the Participant for the taxable year of the Participating Affiliate during which the distribution is made will not be limited by Section 162(m) of the Code.

7.2 - Early Distributions.

At any time, a Participant (or former Participant), at his or her sole discretion, may elect to have 90% of the balance of his or her Accounts distributed in a single lump sum; provided, however, that the remaining 10% of such Accounts shall be forfeited to the Participant's Employer. The 10% penalty shall be permanently and irrevocably forfeited. The Participating Affiliates shall thereafter have no obligation to pay the forfeited amount. In addition, upon an Account distribution and forfeiture pursuant to this Section 7.2, the Participant's deferral election for that Plan Year shall automatically terminate and, notwithstanding anything else contained herein to the contrary, the Participant shall not be eligible to defer any amounts of Compensation under this Plan for the remainder of that Plan Year and the following Plan Year. Notwithstanding the foregoing, a Participant may not elect an early distribution under this Section 7.2 of any amount credited as or in respect of Initial 401(k) Benefits and/or Excess 401(k) Benefits (including earnings thereon).

If a Participant with multiple distribution subaccounts receives an early distribution in accordance with this Section 7.2 from his or her Accounts, his or her distribution subaccounts shall be reduced by the amount of the distribution in the following order:

(1) the portion of the Participant's distribution subaccounts for which an in-service payment date was elected in accordance with Section 3.4 shall be reduced, with the distribution subaccounts having the earliest in-service payment dates being reduced first;

(2) the vested portion of the Participant's distribution subaccounts for which the participant elected a Termination Date distribution shall be reduced.

If two or more distribution subaccounts are to be reduced at the same time in accordance with the preceding sentence, the distribution subaccounts(s) to be paid in the form of a lump sum shall be reduced first.

7.3- Distributions for Unforeseeable Emergencies.

(a) A Participant (or former Participant) may request a distribution for an Unforeseeable Emergency (as defined below) without penalty. Such distribution for an Unforeseeable Emergency shall be subject to approval by the Committee and may be made only to the extent necessary to satisfy the hardship and only from amounts credited to his or her Accounts. The Committee may treat a distribution as necessary to satisfy the hardship if it relies on the Participant's written representation, unless the Committee has actual knowledge to the contrary, that the hardship cannot reasonably be relieved (1) through reimbursement or compensation by insurance or otherwise or (2) by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship. Notwithstanding the foregoing, a Participant may receive a distribution for an Unforeseeable Emergency under this Plan prior to a hardship withdrawal under any plan described in Section 401(k) of the Code.

(b) For purposes of this Section 7.3, an "Unforeseeable Emergency" shall mean a severe financial hardship to the Participant resulting from a sudden and unexpected illness or accident of the Participant or a dependent of the Participant, loss to the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. The circumstances that will constitute an Unforeseeable Emergency will depend upon the facts of each case. Examples of what are not considered to be Unforeseeable Emergencies include the need to send a Participant's child to college or the desire to purchase a home.

(c) If a Participant with multiple distribution subaccounts receives an Unforeseeable Emergency distribution from his or her Accounts, his or her distribution subaccounts shall be reduced by the amount of the distribution in the following order:

(1) the vested portion of the Participant's distribution subaccounts for which an in-service payment date was elected in accordance with Section 3.4 shall be reduced, with the distribution subaccounts having the earliest in-service payment dates being reduced first;

(2) the vested portion of the Participant's distribution subaccounts for which the participant elected a Termination Date distribution shall be reduced.

If two or more distribution subaccounts are to be reduced at the same time in accordance with the preceding sentence, the distribution subaccounts(s) to be paid in the form of a lump sum shall be reduced first.

7.4 - <u>Inability to Locate Participant</u>.

In the event that the Committee is unable to locate a Participant or Beneficiary within two years following the Participant's Termination Date, or if later, within two years following the date on which benefits hereunder are to commence, the amount allocated to the Participant's Deferral Account and Stock Account shall be forfeited. If, after such forfeiture, the Participant or Beneficiary later claims such benefits, such benefits shall be reinstated without interest, earnings or Dividend Equivalents.

7.5 - <u>Payment Discretion</u>.

A Participating Affiliate may, in its sole discretion, settle any Deferred Shares otherwise payable in accordance with this Plan by a cash payment in lieu of Common Stock. The amount of such cash payment shall equal the most recent Fair Market Value of a share of Common Stock as of the date of payment, multiplied by the number of Deferred Shares to be paid in such manner.

The Board or the Committee may, in its sole discretion, accelerate the date payment of the unpaid balance of a Participant's Accounts is to be made (or installments are to commence) in the event of a Participant's retirement, death, permanent disability, resignation or other termination of employment.

7.6 - <u>Liability for Payment</u>.

Notwithstanding anything else in this Plan to the contrary: (1) a Participant's benefits with respect to this Plan shall be paid by the Participant's Employer to which such benefits relate, and (2) a Participant shall have no right or claim to Plan benefits from any other Participating Affiliate other than the Employer referenced in the foregoing clause.

ARTICLE VIII
ADMINISTRATION

8.1 - Committee.

The Committee shall be appointed by, and serve at the pleasure of, the Board of Directors. The number of members comprising the Committee shall be determined by the Board, which may from time to time vary the number of members. A member of the Committee may resign by delivering a written notice of resignation to the Board. The Board may remove any member by delivering a certified copy of its resolution of removal to such member. Vacancies in the membership of the Committee shall be filled promptly by the Board.

8.2 - Committee Action.

The Committee shall act at meetings by affirmative vote of a majority of the members of the Committee. Any action permitted to be taken at a meeting may be taken without a meeting if, prior to such action, a written consent to the action is signed by all members of the Committee and such written consent is filed with the minutes of the proceedings of the Committee. A member of the Committee shall not vote or act upon any matter which relates solely to himself or herself as a Participant. The Chairman or any other member or members of the Committee designated by the Chairman may execute any certificate or other written direction on behalf of the Committee.

8.3 - Powers and Duties of the Committee.

(a) The Committee, on behalf of the Participants and their Beneficiaries, shall enforce the Plan in accordance with its terms, shall be charged with the general administration of the Plan, and shall have all powers necessary to accomplish its purposes, including, but not by way of limitation, the following:

(1) To select the funds or portfolios to be the Funds in accordance with Section 3.2(b) hereof;

(2) To construe and interpret the terms and provisions of this Plan;

(3) To compute and certify to each Participating Affiliate and to any Trustee the amount and kind of benefits payable to Participants and their Beneficiaries, and to determine the time and manner in which such benefits are paid;

(4) To maintain all records that may be necessary for the administration of the Plan;

(5) To provide for the disclosure of all information and the filing or provision of all reports and statements to Participants, Beneficiaries or governmental agencies as shall be required by law;

(6) To make and publish such rules for the regulation of the Plan and procedures for the administration of the Plan as are not inconsistent with the terms hereof;

(7) To appoint a plan administrator or any other agent, and to delegate to them such powers and duties in connection with the administration of the Plan as the Committee may from time to time prescribe;

(8) To authorize all disbursement by a Participating Affiliate and any Trustee pursuant to this Plan and any Trust; and

(9) To direct each Trustee concerning the performance of various duties and responsibilities under the related Trust.

8.4 - <u>Construction and Interpretation</u>.

The Committee shall have full discretion to construe and interpret the terms and provisions of this Plan, which interpretation or construction shall be final and binding on all parties, including but not limited to Participating Affiliates and any Participant or Beneficiary. The Committee shall administer such terms and provisions in a uniform and nondiscriminatory manner and in full accordance with any and all laws applicable to the Plan.

8.5 - <u>Information</u>.

To enable the Committee to perform its functions, each Participating Affiliate shall supply full and timely information to the Committee on all matters relating to the Compensation of all Participants, their death or other cause of termination, and such other pertinent facts as the Committee may require.

8.6 - <u>Compensation, Expenses and Indemnity</u>.

(a) The members of the Committee shall serve without compensation for their services hereunder.

(b) The Committee is authorized at the expense of the Company to employ such legal counsel as it may deem advisable to assist in the performance of its duties hereunder. Subject to Section 7.6, expenses and fees in connection with the administration of the Plan shall be paid by the Company.

(c) To the extent permitted by applicable state law, the Company and each of the other Participating Affiliates shall indemnify and save harmless the Committee and each member thereof, the Board of Directors and any delegate of the Committee who is an employee of a Participating Affiliate against any and all expenses, liabilities and claims, including legal fees to defend against such liabilities and claims arising out of their discharge in good faith of responsibilities under or incident to the Plan, other than expenses and liabilities arising out of willful misconduct. This indemnity shall not preclude such further indemnities as may be available under insurance purchased by a Participating Affiliate or provided by a Participating Affiliate under any bylaw, agreement or otherwise, as such indemnities are permitted under state law.

8.7 - Quarterly Statements.

Under procedures established by the Committee, a Participant shall receive a statement with respect to such Participant's Accounts on a quarterly basis as of each March 31, June 30, September 30 and December 31.

ARTICLE IX
MISCELLANEOUS

9.1 - Unsecured General Creditor.

Participants and their Beneficiaries, heirs, successors, and assigns shall have no legal or equitable rights, claims, or interest in any specific property or assets of any Participating Affiliate. No assets of any Participating Affiliate shall be held under any trust (except as provided in Section 9.2), or held in any way as collateral security for the fulfilling of the obligations of any Participating Affiliate under this Plan. Any and all of each Participating Affiliate's assets shall be, and remain, the general unpledged, unrestricted assets of the Participating Affiliate. Each Participating Affiliate's obligations under the Plan shall be merely that of an unfunded and unsecured promise of the Participating Affiliate to pay money in the future to those persons to whom the Participating Affiliate has a benefit obligation under this Plan (as determined in accordance with the terms hereof including, without limitation, Section 7.6), and the respective rights of the Participants and Beneficiaries shall be no greater than those of unsecured general creditors.

9.2 - Trust Arrangement.

Notwithstanding Section 9.1, a Participating Affiliate may at any time transfer assets representing all or any portion of a Participant's Accounts to a Trust to be held and invested and reinvested by the Trustee pursuant to the terms of the Trust Agreement. However, to the extent provided in the Trust Agreement only, such transferred amounts shall remain subject to the claims of general creditors of the Participating Affiliate that established the Trust. To the extent that assets representing a Participant's Accounts are held in a Trust when his or her benefits under the Plan become payable, the Participating Affiliate that is liable for the payment of such benefits may direct the Trustee (if that Participating Affiliate established a Trust) to pay such benefits to the Participant from the assets of the Trust.

9.3 - Restriction Against Assignment.

The respective Participating Affiliate shall pay all amounts payable hereunder only to the person or persons designated by the Plan and not to any other person or corporation. No part of a Participant's Accounts shall be liable for the debts, contracts, or engagements of any Participant, his or her Beneficiary, or successors in interest, nor shall a Participant's Accounts be subject to execution by levy, attachment, or garnishment or by any other legal or equitable proceeding, nor shall any such person have any right to alienate, anticipate, commute, pledge, encumber, or assign any benefits or payments hereunder in any manner whatsoever. If any Participant, Beneficiary or successor in interest is adjudicated bankrupt or purports to anticipate, alienate, sell, transfer, assign, pledge, encumber or charge any distribution or payment from the Plan, voluntarily or involuntarily, the Committee, in its discretion, may cancel such distribution or payment (or any part thereof) to or for the benefit of such Participant, Beneficiary or successor in interest in such manner as the Committee shall direct.

9.4 - Withholding.

(a) The Company (or the Subsidiary by which the Participant employed) may satisfy any state or federal employment tax withholding obligation with respect to Compensation deferred under the Plan by deducting such amounts from any compensation payable by the Company (or Subsidiary) to the Participant.

(b) There shall be deducted from each payment or distribution made under the Plan, or any other compensation payable to the Participant (or Beneficiary), all taxes which are required to be withheld by the Company (or a Subsidiary) in respect to such payment or distribution or this Plan. The Company (or the Subsidiary by which the Participant is or was employed) shall have the right to reduce any payment or distribution (or other compensation) by the amount of cash and/or shares of Common Stock sufficient to provide the amount of said taxes. To the extent that any shares of Common Stock are withheld, the determination of the appropriate number of shares required to satisfy all or a portion of any such tax will be based on the Fair Market Value of a share of Common Stock on the day prior to the date of distribution. If the Company (or a Subsidiary), for any reason, elects not to (or cannot) satisfy the withholding obligation from the amounts otherwise payable or the shares of Common Stock otherwise distributable under this Plan, the Participant shall pay or provide for payment in cash of the amount of any taxes which the Company (or a Subsidiary) may be required to withhold with respect to the benefits hereunder.

9.5 - Amendment, Modification, Suspension or Termination.

The Board or the Committee may amend, modify, suspend or terminate the Plan in whole or in part, except that no amendment, modification, suspension or termination shall have any retroactive effect to reduce any amounts allocated to a Participant's Accounts. In the event that this Plan is terminated, the amounts credited to a Participant's Accounts shall be distributed to the Participant or, in the event of his or her death, his or her Beneficiary in a lump sum within thirty (30) days following the date of termination. A Participating Affiliate may elect to terminate its status as such at any time and, in such event, (1) such termination shall not affect the Participating Affiliate's obligations under this Plan with respect to amounts previously credited and/or deferred under this Plan (including earnings thereon) for which the Participating Affiliate is liable, and (2) the Participating Affiliate may elect to settle its obligations under this Plan by a cash lump sum payment to the respective Participants within thirty (30) days of such termination.

9.6 - Governing Law; Severability.

This Plan shall be construed, governed and administered in accordance with the laws of the State of Arizona. If any provisions of this instrument shall be held by a court of competent jurisdiction to be invalid or unenforceable, the remaining provisions hereof shall continue to be fully effective.

9.7 - Receipt or Release.

Any payment to a Participant or the Participant's Beneficiary in accordance with the provisions of the Plan shall, to the extent thereof, be in full satisfaction of all claims against the Committee, the Company and its Subsidiaries, and the Trustee. The Committee may require such Participant or Beneficiary, as a condition precedent to such payment, to execute a receipt and release to such effect.

9.8 - Payments on Behalf of Persons Under Incapacity.

In the event that any amount becomes payable under the Plan to a person who, in the sole judgment of the Committee, is considered by reason of physical or mental condition to be unable to give a valid receipt therefore, the Committee may direct that such payment be made to any person found by the Committee, in its sole judgment, to have assumed the care of such person. Any payment made pursuant to such determination shall constitute a full release and discharge of the Committee, the Company and its Subsidiaries.

9.9 - No Right to Employment.

Participation in this Plan shall not give any person the right to continued employment or service or any rights or interests other than as herein provided. No Participant shall have any right to any payment or benefit hereunder except to the extent provided in this Plan.

9.10 - Compliance with Laws.

This Plan and the offer, issuance and delivery of shares of Common Stock and/or the payment of money through the deferral of compensation under this Plan are subject to compliance with all applicable federal and state laws, rules and regulations (including but not limited to state and federal securities law) and to such approvals by any listing, agency or any regulatory or governmental authority as may, in the opinion of counsel for the Company or a Subsidiary, be necessary or advisable in connection therewith. Any securities delivered under this Plan shall be subject to such restrictions, and the person acquiring such securities shall, if requested by the Company or a Subsidiary, provide such assurances and representations to the

Company or the Subsidiary as the Company or the Subsidiary may deem necessary or desirable to assure compliance with all applicable legal requirements.

9.11 - <u>Plan Construction</u>.

It is the intent of the Company that transactions pursuant to this Plan satisfy and be interpreted in a manner that satisfies the applicable requirements of Rule 16b-3 promulgated under the Exchange Act ("Rule 16b-3") so that, to the extent elections are timely made, the crediting of Deferred Shares, the distribution of shares of Common Stock and any other event with respect to Deferred Shares under the Plan will be entitled to the benefits of Rule 16b-3 or other exemptive rules under Section 16 of the Exchange Act and will not be subjected to avoidable liability thereunder.

9.12 - <u>Headings, etc. Not Part of Agreement</u>.

Headings and subheadings in this Plan are inserted for convenience of reference only and are not to be considered in the construction of the provisions hereof.

9.13 - <u>Government and Other Regulations</u>.

The obligations of the Company and each other Participating Affiliate to issue or transfer and deliver shares of Common Stock with respect to Deferred Shares credited to Participant's Stock Accounts under the Plan shall be subject to (a) the effectiveness of a registration statement under the Securities Act of 1933, as amended, with respect to such issue or transfer, (b) the condition that the shares of Common Stock authorized to be issued hereunder shall have been listed (or authorized for listing upon official notice of issuance) upon each stock exchange on which outstanding shares of Common Stock may then be listed and (c) all other applicable laws, regulations, rules and orders which shall then be in effect.

9.14 - <u>Claims Procedure</u>.

A person who believes that he or she is being denied a benefit to which he or she is entitled under the Plan (hereinafter referred to as "Claimant") may file a written request for such benefit with the Committee, setting forth his or her claim. The request must be addressed to the Committee at the Company's then principal executive offices.

Upon receipt of a claim, the Committee shall advise the Claimant that a reply will be forthcoming within ninety (90) days and shall, in fact, deliver such reply within such period. The Committee may, however, extend the reply period for an additional ninety (90) days for special circumstances. If the claim is denied in whole or in part, the Committee shall inform the Claimant in writing, using language calculated to be understood by the Claimant, setting forth: (i) the specified reason or reasons for such denial, (ii) the specific reference to pertinent provisions of the Plan on which such denial is based, (iii) a description of any additional material or information necessary for the Claimant to perfect his or her claim and an explanation why such material or such information is necessary, (iv) appropriate information as to the steps to be taken if the Claimant wishes to submit the claim for review, and (v) the time limits for requesting a review set forth below.

Within sixty (60) days after the receipt by the Claimant of the written reply described above, the Claimant may request in writing that the Committee review its determination. Such request must be addressed to the Committee at the Company's then principal executive offices. The Claimant or his or her duly authorized representative may, but need not, review the pertinent documents and submit issues and comments in writing for consideration by the Committee. If the Claimant does not request a review within such sixty (60) day period, he or she shall be barred and estopped from challenging the Committee's determination.

Within sixty (60) days after the Committee's receipt of a request for review, after considering all materials presented by the Claimant, the Committee will inform the Claimant in writing, in manner calculated to be understood by the Claimant, of its decision setting forth the specific reasons for the decision and containing specific references to the pertinent provisions of the Plan on which the decision is based. If special circumstances require that the sixty (60) day time period be extended, the Committee will so notify the Claimant and will render the decision as soon as possible, but no later than one hundred twenty (120) days after receipt of the request for review.

IN WITNESS WHEREOF, the Company has caused this document to be executed by its duly authorized officer effective as of January 1, 2001.

UNISOURCE ENERGY CORPORATION

By: ______________________________

Print Name: ________________________

Its: ______________________________

National Asso of Regulatory Util Com

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EXHIBIT
ALL-STATE LEGAL®
S-17
admitted

GAS DISTRIBUTION RATE DESIGN MANUAL

Prepared by
NARUC Staff Subcommittee on Gas

June 1989

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previously serviced with natural gas. The basis for this rate is the relationship of current consumption to a selected base year where the load was not serviced by the gas utility. All consumption in excess of the base volume would receive a discount from the normal tariff rate. The discount, or incentive, could take the form of a percentage of full tariff, possibly with step discounts for increased consumption or it could take the form of a stated flat rate. In either instance, the customer would continue to purchase base volumes at the full stated tariff rate, and all incremental consumption would receive the discount. Implementing such a rate does present potential discrimination problems. Depending upon the magnitude of the discount the utility could be providing service to customers with similar characteristics at widely divergent rates. Such a situation, particularly if the customers were competitors and energy was a significant element of their cost of goods sold, could be unduly discriminatory.

F. Other Factors

1. Historical Rates

The utility's currently existing rate structure and the history of changes in that structure should be considered when a new rate design is contemplated. If the existing structure works reasonably well, there will likely be considerable reluctance to change it. Even when there is convincing evidence that major changes are needed, Commissions will often utilize the concept of gradualism to make a series of small incremental changes rather than a large revolutionary change. Rate design changes which can be postured as improvements on the existing system are more likely to find acceptance because they maintain continuity and minimize problems due to misunderstanding.

EXHIBIT
S-18
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPOERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

REDACTED

DIRECT

TESTIMONY

OF

GEORGE E. WENNERLYN

ON BEHALF OF

ARIZONA CORPORATION COMMISSION STAFF

FEBRUARY 9, 2007

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EXHIBITS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463 ET AL

I have been asked by the Arizona Corporation Commission Staff to perform a general review of the UNS Gas PGA: preparing an historical record of prices paid by the Company, comparing supply purchases to hub pricing, evaluating the UNS Gas decision making process to supply selection and other related findings. My assessment of prudence and reasonableness covered the period of September 1, 2003 and ending December 31, 2005.

From this review came the following findings and recommendations:

1. The UNS Gas natural gas procurement, practices, and policies achieved the appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. The purchases were reasonable and prudent for the review period.

2. There are a number of improvements which the Company can make on a going-forward basis that should enhance the Commission Staff's purchasing review process and understanding, involving the monthly Purchase Gas Adjustor filings. The Commission should require UNS Gas to include the additional pieces of information outlined in my testimony.

3. UNS Gas needs to complete a study of the costs and benefits of the present gas supply arrangement with BP Energy as compared to other market suppliers, and present their findings to the Commission for review and complete understanding.

I. INTRODUCTION

Q. Please state your name, and business address.

A. My name is George E. Wennerlyn and my business address is 1549 Grosse Point Drive, Middleton, Wisconsin 53562.

Q. Please state your reason for involvement in this proceeding.

A. I am testifying on behalf of the Arizona Corporation Commission, Utilities Division.

Q. Please advise the Commission on your qualifications.

A. I have over 38 years of experience in the energy and natural gas industry. Following graduation from the University of Minnesota with a Bachelor of Science in Business Administration degree, I went to work at the Wisconsin Power and Light Company. During my 26 years of employment with the utility, I held supervisory and management positions in the areas of electric and natural gas rate design, natural gas engineering, and natural gas supply planning and purchasing. My involvement in these functions began in mid-1980 as natural gas was being deregulated. Additionally, I served as director for A&C Enercom Consultants, Inc., a consulting firm acquired by WP&L Holdings to supply energy-related services to the electric and gas utility end-users. Finally, in 1996 I formed my own consulting firm named Select Energy Consulting, LLC (SEC). My firm assists commercial, institutional, and industrial clients in natural gas supply planning, cost-benefit analysis, contract development, and gas purchasing. I also monitor the state regulatory process for rate making and policy changes that would impact client interests.

In 2003, SEC and MSB Energy Associates (MSB) teamed up to provide expert analysis of the risk management strategies of an electric utility's purchases of natural gas for electric generation in the state of Wisconsin. The utility had proposed a plan to manage gas costs through financial means and requested recovery of $1.5 million in rates. On behalf of the Citizens' Utility Board, we analyzed the plan and the likelihood that it would result in ratepayer benefits, and concluded that it would not be in the ratepayer interests given the proposed strategies and the gas markets.

Similarly, in 2004 MSB and SEC once again joined forces in Southwest Gas Corporation Docket No. 03-12012 on behalf of the Staff of the Public Utilities Commission of Nevada. We were asked to assess the prudence and reasonableness of gas purchases for the historical period beginning February 1, 2003 and ending January 31, 2004; the hedging and other financial options used to manage gas price risk including alternatives to simply paying the gas inventory charge; and to investigate Southwest Gas' policy to diversify gas supply by various basins.

The Bureau of Consumer Protection (BCP) for Nevada requested our involvement in Docket 04-7004 to review, advise and present testimony on the Energy Supply Plan 2004-2006 (Volume III) filed by the Sierra Pacific Power Company (SPPC). We also testified on behalf of the BCP regarding Nevada Power Company's (NPC) Energy Supply Plan in Docket 04-9004. Again in 2005, the BCP asked MSB and SEC to review and present testimony based on our findings on SPPC's Energy Supply Plan filed for 2006-2007 in Docket 05-9016.

Attached is Exhibit GEW-1 which provides expanded detail of my professional background.

Q. What is the purpose of your testimony?

A. We have been asked by the Arizona Corporation Commission Staff to focus on the following issues in this docket for UNS Gas, Incorporated (UNS Gas or the "Company"):

I. Perform a general review of the UNS Gas PGA, and prepare an historical record of prices paid by the Company and evaluate the supply purchases for reasonableness based on hub pricing and other available industry data.

II. Evaluate the UNS Gas hedging policies and procedures for reasonableness.

III. Evaluate the UNS Gas decision making processes and procedures in bidder award and evaluation. This will include, but is not limited to, an evaluation of the UNS GAS internal approval process and the presence and execution of internal checks and balances.

IV. Determine if the use of the same personnel to procure gas for UNS and TEP poses "code of conduct issues" and /or "conflict of interest" issues.

V. Examine the UNS Gas interstate pipeline capacity portfolio and the Company's management of its pipeline capacity.

VI. Review and analyze the UNS Gas natural gas procurement policies and procedures for reasonableness and prudence. Assessment of prudence and reasonableness of gas purchases for historical period beginning September 1, 2003 and ending December 31, 2005.

In this testimony, I will address the above. My associate, Mr. Jerry Mendl of MSB Energy Associates will address the assessment of the Company's gas purchase timing practices which is part of issue VI.

Q. How did you evaluate the UNS Gas natural gas purchasing practices and the reasonableness of their acquisitions?

A. The first step in evaluation was to develop a background understanding of the Company's purchasing practices. A series of questions were developed to gain that understanding. Commission Staff then submitted a series of discovery questions to the Company. Following the receipt of responses, additional analysis ensued. On July 12, 2006 an on-site meeting was held at UNS offices in Tucson involving Commission Staff and UNS Gas personnel. This encounter allowed for the opportunity to obtain a more complete understanding of purchasing activities, pipeline issues, internal risk management, approaches, and the Company's purchasing strategies.

From this review process developed a period of in-depth analysis to look into the many issues of gas purchasing to complete the portfolio of supplies required to meet system demands.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q, Would you please summarize your testimony and recommendations?

A. Yes, I will with the following conclusions:

1. My review of the UNS Gas natural gas procurement, practices, and policies determined that the Company achieved the appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. The purchases were

reasonable and prudent. This finding covers the period of September 2003 through December 2005.

2. From key audit findings there are a number of improvements which the Company can make on a going-forward basis that should enhance the Commission Staff's purchasing review process and understanding involving the monthly Purchase Gas Adjustor (PGA) filings. The Commission should require UNS Gas to include the following additional pieces of information in each monthly filing:
   a. Copies of EPNG's and Transwestern's monthly Allocation Statements.
   b. Specific hedging detail for each gas purchase transaction.
   c. Notational (written) information for each transaction (hedges) on the monthly supply invoice(s).
   d. Automatically submit complete documentation required for Commission Staff to complete a reconciliation of the monthly PGA.

3. Under the current contract structure with BP Energy, the energy supplier acts as an agent and manager for both required gas supply and pipeline responsibilities. That relationship may or may not serve the best interests of the retail customer from a cost-perspective. Recently approved pipeline changes (January 2006) have increased daily obligations by UNS Gas personnel that were previously handled by BP personnel. UNS Gas needs to complete a study of the costs and benefits of this supply arrangement versus other market options, including the use of other gas suppliers. They should present their findings to the Commission for review and complete understanding.

III. MONTHLY REVIEW OF THE UNS PURCHASE GAS ADJUSTOR (PGA) FILING

Q. Would you please discuss your analysis of the UNS Gas monthly PGA filing for the September 2003 through December 2005 period?

A. Yes, I will. Commission Staff requested a general review of the UNS Gas PGA, including the comparison of historical prices paid by UNS Gas to actual market prices at commonly used pricing points. The objective of this review was to make a determination regarding the UNS Gas purchases in terms of reasonableness and prudence.

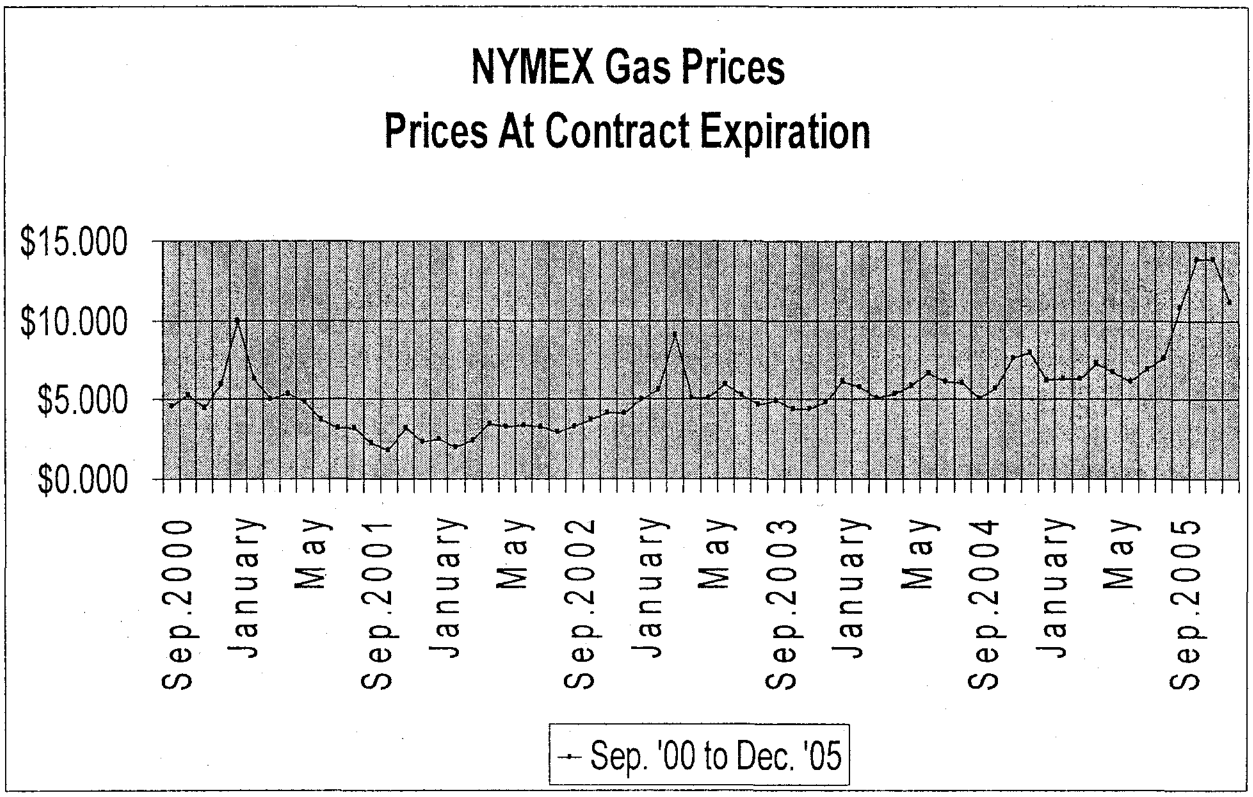
To complete this step, the submitted PGA monthly filings were used as the reference source with a focus on the prices paid for natural gas for the Company's retail customers as compared to hub pricing at the points of purchase. In making this analysis, it was important to isolate the gas costs in such a manner as to insure that comparable cost comparisons remained valid. The actual UNS Gas monthly gas costs were compared to the first-of-the-month published gas prices (hub prices) at the major purchase points used by the utility. The purchase points included the San Juan basin, the Permian basin, and Waha. Additionally, each hub price was weighted by the actual volume of gas purchased at that point without the cost of transportation from the hub to the UNS Gas city-gate. Also excluded from this comparison were the incurred costs of non-retail utility customer's (Negotiated Sales Plan (NSP) customers) and interest charges on select carrying accounts. Effectively, the comparisons were only comprised of commodity costs.

Referring to Exhibit GEW-2 you will find a table which displays the results of the price comparisons. Included in the analysis are the price variances and the monetary impacts of those differences for each month, for the review period, with partial and whole calendar year running totals.

Q. What interpretations did you make for the price comparisons reflected in the exhibit?

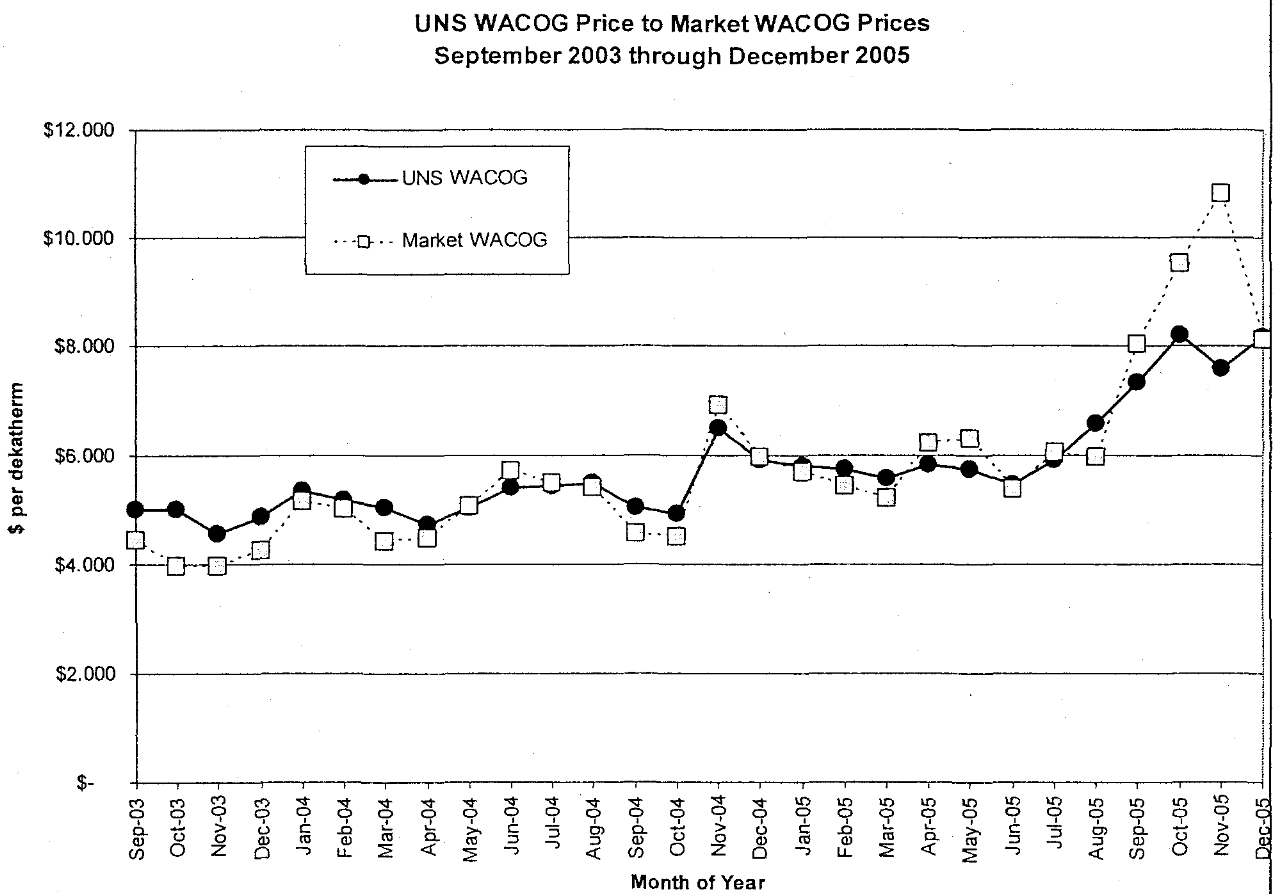
A. Early in the review period (following the acquisition of the gas utility from Citizens Communication Company – Arizona Division), the utility's weighted-average cost of gas was above the comparable hub prices used for its gas supply. I do not believe this was a function of ownership differences but simply the results of earlier purchases and market trends in gas prices. Citizens' gas purchasing practices were similar to those followed by UNS Gas after the acquisition. Both had a plan to begin acquiring a portion of required gas supplies 36 months in advance of actual deliveries.

Looking at the chart below of monthly natural gas prices listed on the New York Mercantile Exchange (NYMEX) will help to address this comparison and the general understanding of price trends. While NYMEX prices do not translate into actual prices paid at San Juan, Permian, or Waha, there is a high correlation (generally above 90%) between the price movements, which simplifies the comparison to one hub (NYMEX) rather than to multiple hubs (San Juan, Permian, Waha).



The initial "above market" price comparisons in the exhibit are difficult to determine given the change in ownership, coupled with early purchases. As you can see in the graph above, the NYMEX 'price trend was moving upward prior to September 2003, followed by a brief price decline that ended in December 2003. Comparisons of UNS Gas prices for the September 2003 through April 2004 period were not very favorable to first-of-the-month market prices. In fact, the unfavorable trend continued into early 2005 when the entire energy complex came under price pressure due to increasing oil prices. Then, the advanced purchases made by UNS Gas proved valuable to retail customers from a cost viewpoint. The summer hurricanes of 2005 (Katrina and Rita) caused dramatic price increases and price volatility, which the UNS Gas purchase strategy significantly dampened.

Below is a graph of UNS Gas' weighted-average cost of gas as compared to the first-of-the-month weighted-average cost of gas at the pricing hubs (Permian, San Juan, and Waha) covering the September 2003 to July 2006 period. UNS Gas relies primarily upon these hubs for its gas supplies and the pricing curve below reflects their actual percentages purchased from each hub for the respective months shown:



If retail gas were acquired using a first-of-the-month purchase strategy rather than the 36-month advance purchase strategy, the results reveal that in 17 months of the 28 month review period UNS Gas prices were above market.

Q. Were these comparison results surprising to you?

A. No, they are not. I would expect these comparison patterns will continue in future months as gas prices trend either upward or downward. Generally there will be a lag in UNS Gas retail prices in both price trend directions, with Company prices either above current market prices or below current market prices given the 36-month strategy. UNS Gas follows a purchase plan which includes both "non-discretionary" (must acquire) and "discretionary" (may acquire) advanced purchases for any delivery month. The actual degree of lag may be influenced by the amount of "discretionary" gas purchased by the Company for that month.

Q. Would you summarize your comments on the reasonableness of the above price comparisons?

A. Yes. As you can see in the above graph, on a month to month basis there is a "cost" to the 36-month purchasing strategy followed by the utility. Here, I define "cost" as the difference between the UNG Gas average cost of gas for the month and the first-of-the-month cost of gas at market hub prices.

However, raw price comparisons need to be weighted by the volumes of gas purchased for each of the months in order to determine the actual cost or benefit to the retail customer. When the above price differences and volumes are factored in together, the comparison results become more favorable:

Year	UNS Gas costs to WACOG Hub prices
2003 (partial: Sept. – Dec.)	+13.8% more
2004	+ 1.7% more
2005	- 5.8% less
Entire 28 month period	- 0.7% less

For the entire 28-month period the resulting -0.7% (less costly) is very acceptable in my opinion. I would find a value of +20% in added cost (commodity only) for an extended period of time (twelve month period) to be a point where a re-evaluation of the established purchasing strategy would be merited. This 20% variance is completely arbitrary reflecting my values and expectations. For others who monitor price comparison performance (UNS Gas, Commission Staff, Consumers) the percentage variance may be more or less.

Q. Please clarify your comments regarding a re-evaluation of the established purchasing strategy.

A. I believe that a natural gas purchase strategy needs to be viewed as a living document, one that needs to be revisited throughout the year. I believe this approach is required given the ever changing conditions found in the marketplace. For example, following the hurricanes of 2005 the price for natural gas increased substantially. Unlike UNS Gas, a utility who relied upon the use call options as part of their own price stabilization policy, that strategy would quickly be called into question given the high financial transaction cost of an option. Circumstances quickly changed, resulting in a review of purchase policies for some utilities, necessary to insure that what had been established should continue to be followed.

Once a set purchase plan is in place, you cannot place that process on auto-pilot control. You must review and insure that what is in place still makes sense to do. If you fail to do so, your actions and inactions may become imprudent from a customer's viewpoint.

Q. When reviewing the monthly PGA filings, did you encounter any problems in reconciling the costs to the natural gas quantities included in the report?

A. Yes, I did encounter problems in matching volumes that appeared on the monthly BP supply invoice to the volumes and charges received from the two pipelines (EPNG and TW).

Understandably, the monthly invoice from BP reflects scheduled delivery volumes (which are estimates of required monthly supply) and not actual consumed volumes (metered-measured). This process is followed by BP and the Company in order to insure a timely billing process which reduces the lag time until all gas volumes are verified and balanced. Each month UNS Gas personnel complete this review and make corrections accordingly. Thus, when scrutinizing any monthly supply invoice, you will invariably find hand-written changes in volumes delivered as compared to volumes consumed (measured). Thus, the dollar amounts billed change as well. The BP invoice, with the noted adjustments (corrections), is included in the filed PGA.

Q. Can you provide an example of this monthly reconciliation process of the BP invoice?

A. Yes, I can. For the month of December 2005, the table below summarizes the original invoice to reconciled BP invoice:

BP Energy	Original Invoice	Reconciled Invoice	Percent Variance to Original Invoice
Volume (Dths)	[redacted]	[redacted]	+4.6%
Amount Billed ($)	[redacted]	[redacted]	+1.0%

The pipelines also issue monthly invoices to UNS Gas and both are included in the monthly filed PGA. The documents are required to complete any reconciliation; however, they are not sufficient to complete reconciliation with the billed (after adjustments) volumes which appear on the BP invoice.

Q. What additional information is required?

A. For a complete reconciliation, the monthly El Paso Natural Gas Allocation Statement and the monthly Transwestern Pipeline Company Contract Balance Statement are required as they show the "scheduled" volumes as compared to the actual "measured" (metered) volumes. The difference between the two totals represents the imbalances between scheduled and actual deliveries.

Q. Is there a simple resolution to this information requirement?

A. Yes, there is. UNS Gas should be required to automatically include the additional statements (and other documents that evolve as pipeline services change) when filing the monthly PGA.

Q. Is there any other information that is needed to adequately complete the monthly PGA reconciliation?

A. Yes. The monthly BP invoice lacks adequate information necessary to link the multiple gas purchase transactions which take place prior to the delivery month. As a result, it is difficult to match actual purchases (advanced hedges) to the quantities appearing on the invoice. To facilitate the regulatory review process, UNS Gas should be required to add written notes on the supply invoice linking that specific transaction detail to a specific purchase. In response to one of our data requests, UNG Gas provided a form used by UniSource Energy Services titled "Hedging Activity Detail". That form, or similar information included from that form, should be included with each PGA filing

Q. Prospectively, should the Commission order other PGA filing requirements on UNS Gas?

A. Yes. The Commission should request that all necessary documents required for completing a reconciliation of supply invoices and pipeline statements be automatically included with each filing.

IV. EVALUATE THE UNS GAS HEDGING POLICIES AND PROCEDURES FOR REASONABLENESS

Q. Please present your evaluation of the UNS Gas 36-month hedging policy.

A. To answer that question, I would like to refer you to Exhibit GEW-3 which presents the actual contracts entered into by UNS Gas for the period of review. This exhibit looks at each individual purchase, and compares that purchase to the New York Mercantile Exchange (NYMEX) futures market prices which existed for that specific month over the "36-month life" of that particular contract. The phrase "36-month life" is based upon the Company's written policy of when they will begin purchase of a specific month's supply requirement. It does not reflect the actual "life" of a NYMEX contract and could be different for any other utility that followed a different purchase strategy.

The comparison calculates the total cost of the gas package the Company acquired and measures that value to the highest and lowest price established during that same 36-month purchasing period.

From these three calculations, I then develop a "ranking index", which measures (as a percentage) where the actual purchase falls along the continuum between the 36-month highest NYMEX price and the 36-month lowest NYMEX price in the defined purchase period.

Q. How do you account for that basis adjustment factor, which reflects the price difference between the San Juan or Permian pricing hubs and the NYMEX price which is at the Henry Hub?

A. The "basis differential" must be removed from the actual purchase price in order to make the transactions comparable to the NMYEX prices, which are quoted at the Henry Hub in Louisiana. You must remove the adjustment from the trigger price before comparing the NYMEX equivalent price to historic high and low prices. You need to insure an "apples to apples" comparison.

Q. Please explain the rationale for using this type of hypothetical comparison.

A. Each monthly contract traded on the exchange (NYMEX) has a trading life of some 6 years. Currently, as an example, one could purchase gas utilizing a NYMEX contract for the month of December in the year 2012. For the entire time period until the date arrives where December 2012 can no longer be traded (upon settlement in November 2012), the pricing history for that specific month contract is being tracked. Between the present date and the ending date there is always the potential that either a new high or low price will be established.

With that in mind, a natural gas buyer has the opportunity to buy that NYMEX contract at anytime during its "life". Based on one's purchase strategy, judgment, timing, and good or not-so-good fortune, a buyer could end up purchasing that contract at a pricing point anywhere along the continuum between the highest price and the lowest traded price. For UNS Gas, this NYMEX comparison provides a view to a 36-month purchase horizon, given the Company's strategy is based on that timeframe. Indeed, you can measure or "rank" any given purchase by comparing the price you triggered to the actual life high and low price values or any other defined period, such as 36 months.

For purposes of understanding, an example helps to show the value of the comparison. The formula is:

$$\%\ \text{Ranking} = \frac{\text{(Actual Price “at NYMEX” – Lowest 36-month Price)}}{\text{(Highest 36-month Price – Lowest 36-month Price)}}$$

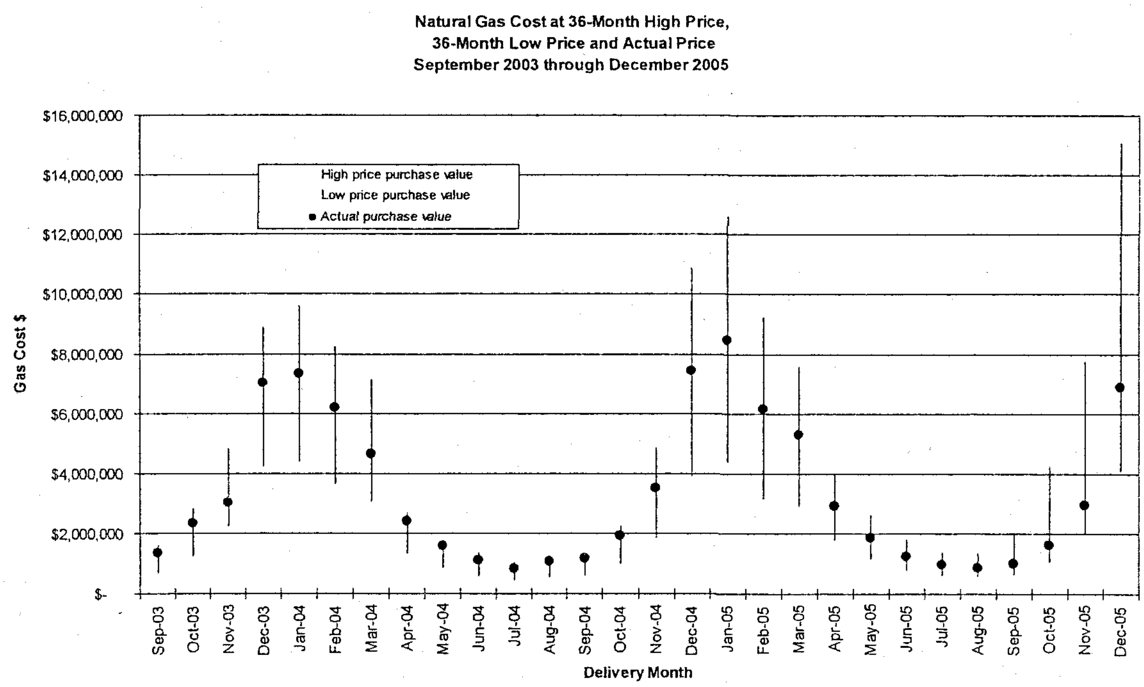
For example, assume you buy one unit of gas per day for December 2005, at a cost of $8.40 per unit. The NYMEX contract cost for the month would be $260.40 or (1 unit * 31 days * $8.40). If, however, you had purchased that contract at the lifetime high price which was $14.67, then your cost for the month would have been $454.77 (1 unit * 31 days * $14.67). Or, perhaps with good fortune you purchased the one unit of gas at the lifetime low of $3.99 per unit. The cost of that contract would have been $123.69 (1 unit * 31 days * $3.99).

To determine the "ranking" of your purchase you would follow the above formula and calculate the difference between the 36-month high cost of the purchased package and the calculated lifetime low cost. Then, take the actual purchase price you made (at NYMEX) and also subtract the low 36-month price package cost. The lowest lifetime price serves as the benchmark for measurement purposes, as it would be the most preferred price by any successful natural gas buyer. So, for our example above, the ranking of the one December 2005 purchase would be:

($260.40 less $123.69) divided by ($454.77 high less $123.69 low) =41% ranking

It is important to keep in mind that in ranking purchases with the lowest price being used as the benchmark, that the 0% (the lowest price) value is the most preferred and 100% (the highest price) value is the least preferred. Interpreting either individual or annual purchases, if you bought gas at a point that is less than the mid-point of 50%, but above the optimum level of 0%, most analysts would view the result favorably if corroborated by other cost comparisons. In addition to looking at individual purchases, you can also calculate combined purchases to arrive at an overall ranking for the period under review.

Below is a graph which reflects this analysis of high and low prices for the 36-month period of the NYMEX contract. UNS Gas's purchases garnered a ranking which ranged from a one-month high of 81% (May 2004) to a one-month low of 17% (November 2005) on the graph. Overall, the ranking for UNS was 48% for the entire 28 month period of review.



Q. Is this ranking an indication of purchasing quality?

A. No, it is not meant to be a solitary quality measurement. It can be used as an indicator of purchase quality, but only if other analysis supports that finding.

Additional analysis needed to support this measurement would include understanding how the UNS Gas - NYMEX purchase price compared to the average price established over the 36-month life of the NYMEX contract. While the above described ranking of purchases provides a quantitative tool to evaluation, there can be distortions to price that could impact this analysis. For instance, one only needs to look back at the NYMEX contract for the month of March 2003. Just one month before the March contract expired, the high lifetime price was \$5.75. However, during the last days of trading in February 2003, based on market fears relating to supply adequacy, the market spiked to a new high of \$11.899. Depending on when a gas buyer purchased a March 2003 NYMEX contract, the results could be very misleading. Therefore, it should be used as one component in a larger review that includes other market perspectives, such as prevailing prices over time, and price comparisons to supplies available at different resource basins. During the actual UNS Gas review period, the hurricanes of 2004 and 2005 created similar price impacts.

Q. Did you review the Company's use of financial instruments to manage price risk?

A. Yes, I did. Presently, UNS Gas purchases approximately 45% of their total gas requirements using the financial instruments of hedging gas futures and basis swaps. UNS Gas does not directly enter into these transactions, but indirectly through their supplier. To further eliminate price risk, there are other risk management tools which can be utilized including the use of call options and price collars, to name a few. However, the use of these instruments does not insure that all risks will be avoided or gas costs minimized. On the contrary, they can have an incremental impact through additional staffing or outsourcing requirements, along with the cost of the financial instruments. Moving beyond the current utilization level of financial tools requires clear definition to protect the customers and the Company. This includes a multitude of issues, from the separation of the accounting and the purchasing functions as it relates to financial transactions, to the required protections needed to prevent speculation. All need to be defined to prevent harm both consumers and UNS Gas shareholders. An example of a potential activity that could cause harm would be the acquisition of a stand-alone put option, a sign that speculative trading might be present. That should not be part of a utility's gas purchasing activity.

Prior to expanding the use of additional financial alternatives, considerable effort by all stakeholders will be required to define the boundaries necessary to implement such a strategy. Until that process is complete, in my opinion, the present use of financial instruments (third party hedging and swaps) for the purchase program is sufficient. This already represents 45% of the gas portfolio.

V. EVALUATE THE UNS DECISION MAKING PROCESS FOR GAS SUPPLY SELECTION

Q. Please describe you investigation into supplier selections and contract awards.

A. UNS Gas assumed a gas supply contract when acquiring the Citizens Communication Company – Arizona Gas Division in 2003 which was served by BP Energy Company (BP). The contract term ended in August of 2005. However, under the provisions of the supply contract, the agreement could be extended by the utility year-to-year which they have elected to continue.

Under the agreement, BP acts as an agent of UNS Gas, purchasing gas supplies and managing the transportation services received from the pipelines that have contractual relationships with UNS Gas. The pipelines include El Paso Natural Gas (EPNG) and Transwestern Pipeline Company (TW). BP orders gas as requested by the Company and optimizes idle pipeline capacity for the utility, selling-off unused capacity to a third party. If BP is successful in that activity, both UNS Gas and BP share in the revenue from that capacity sale on a 50/50 basis. BP also assumed full responsibility for any imbalances that may exist on upstream pipelines. In effect, BP provided full requirement supply services to UNS Gas.

Q. Do those same services exist today between BP and UNS Gas?

A. No, they do not. The roles and responsibility changed due to new EPNG tariff and service proposals. The supply agreement between BP and UNS Gas was altered to reflect these changes, effective starting January 1, 2006.

Q. Did you discuss this arrangement with BP at your meeting with UNS personnel?

A. Yes, we did. During the discussions on supply acquisition UNS Gas reviewed the on going changes that were being made due to operational changes on the EPNG pipeline. The Company indicated that given the changes with daily nominations and balancing issues that the role of UNS Gas personnel was changing, too. No longer was BP able to manage the daily gas dispatch responsibilities with the pipeline without closer daily scrutiny and daily through-put estimates from the Company. Included in the modified agreement, UNS Gas is now responsible for differences between forecasts and actual usage and the cost of those variances. Additionally, UNS Gas relies more on the daily spot index for added supply needs. As a result, UNS Gas indicated that a review of their current contract was planned sometime in the future.

Q. Do you believe such a study should be conducted by UNS Gas?

A. Absolutely. The Company needs to determine if managing the entire spectrum of daily responsibilities for a typical gas distribution company would provide a financial benefit to its retail customers. Operating with total and direct responsibility, UNS Gas would be required to solicit gas supplies from a number of prospective gas suppliers, and determine if more competitive pricing would be available to them rather than sole reliance on BP. Additionally, the Company would assume full responsibility for both purchasing and selling unused pipeline capacity to address seasonal fluctuations without the 50/50 sharing mechanism the two parties presently follow.

The Commission should request and review the study results to insure that the interests of the retail customer are being maximized by the present contract relationship with BP.

VI. DETERMINE THE USE OF UNS PERSONNEL IN PROCURING GAS SUPPLIES FOR UNISOURCE ENERGY ENTITIES AND EVALUATE POSSIBLE "CODE OF CONDUCT" OR "CONFLICT OF INTEREST ISSUES".

Q. Did you look at the use of Company personnel in procuring gas supplies for the gas utility, UNS Electric, and Tucson Electric Power Company (TEP)?

A. Yes, we did. During our joint meeting with Company personnel we reviewed internal reporting relationships, the management of the various internal functions, the approval process and execution of internal checks and balances. The Fuels & Wholesale Power Department for UniSource Energy handles the functions of coal and rail contracting, natural gas and transportation, contract management and accounting, and fuel procurement activities. The organizational structure is similar to other combination gas and electric utilities, with combined purchasing activities carried out by one office for the entire Company.

What currently makes the UniSource Energy organization unique to other combination utilities are the supply arrangements in place for UNS Gas, TEP, and UNS Electric. For UNS Gas, the previously mentioned BP contract which transfers a portion of the daily management activities to another entity (BP) whereas a combination utility normally manages the daily functions for supply acquisition and pipeline capacity management. Similarly, UNS Electric has a full requirements contract with Pinnacle West, a relationship which extends into mid-2008. And for TEP, they hedged their own gas supplies but do not procure nor schedule the deliveries, as that function is provided by Southwest Gas Company.

Q. What codes of conduct are followed by the Fuel & Wholesale Power group?

A. Our review of UNS Gas procurement activities included an understanding and assessment of the UNS Gas' Price Stabilization Policy. This written policy appears in the Company's Exhibit DGH-1. The policy states the Company's plan objectives, the hedging procedures of the UNS Gas unit, levels of purchase authorization, the assignment of transaction responsibilities and related job functions by company position, organizational levels of approval, and management reporting. Each employee is required to know and provide signed acknowledgment of their compliance with the stated policies. In my view, the policies clearly and adequately define the appropriate functions and position responsibilities necessary to carryout a fuel procurement activity.

Q. Do you see any potential conflicts of interest within the UNS Gas organization, and specifically the Fuels & Wholesale Power group?

A. No, I do not. In a data request, UNS Gas provided a copy of the UniSource Energy Corporation's Energy Risk Control Policies Manual which outlines the risks relating to wholesale power trading, and fuel and power procurement. The manual defines lines of authority, responsibility, and accountability related to energy procurement, trading and marketing. Moreover, the manual defines the risks, including internal administrative risks, market price risk, accounting and tax related risks, and regulatory risks. These risk control policies are incorporated into the separate policies followed by UNS Gas, UNS Electric, and TEP. Important to any potential conflict of interest, the manual describes the internal organization structure and the deliberate separation of job functions. Commonly called the "front", "middle", and "back" offices, functions are organizationally structured to separate different job activities. For instance, the energy trader function is a separate position as compared to the position of a risk manager. Additionally, the credit manager organizationally reports to an entirely different part of the corporation.

Between these two documents, the Company has outlined justifiable standards of conduct. Moreover, there was no indication of problems associated with the day-to-day conduct of business during our interview with UNS Gas personnel.

I would like to make one final comment relating to the area of conduct and potential conflict. Given the current fuel procurement relationships established with BP, Southwest Gas, and Pinnacle West, coupled with the defined policies which the Company has established internally to insure compliance and avoid risk, I believe there is less concern or chance for collusion or misconduct. One could argue that changing roles with supplier BP, Southwest Gas, or Pinnacle West could heighten the potential to these two concerns.

That might raise the level of concern and result in greater scrutiny. However, for the moment I believe the established safe guards are in place to minimize that potential.

VII. EXAMINE THE UNS GAS INTERSTATE PIPELINE CAPACITY PORTFOLIO AND THE MANAGEMENT OF ITS PIPELINE CAPACITY.

Q. Did you complete a review of the UNS pipeline portfolio?

A. Yes I did, both in general terms and comparisons between pipeline contractual rights and peak-day experience during the review period. Data requests were submitted to learn about the month-to-month demands on the UNS Gas system which focused on the upstream pipeline contracts, and rights to capacity for the core markets. In my review it became obvious for the short-term, that firm peak-day capacity becomes tight during the months of October and November. This means that reserves are narrowed to less than ±10%. This finding was confirmed by UNS Gas personnel when they discussed the strategy for rectifying the situation. In addition to the constrained months, the growth on the "Phoenix lateral" needs to be addressed as well. The communities located between Flagstaff and Phoenix (off the TW pipeline) have experienced considerable growth in recent years. UNS Gas personnel outlined the on-going discussions with the pipelines, their plans for reconfiguring the pipeline contracts, contract expiration dates and opportunities for capacity acquisition and release.

This strategy discussion covered the short-term and long term (current through 2018 horizon) planning period. UNS Gas addressed the current pipeline portfolio they manage and outlined the challenges and plans for the future to insure adequate coverage for core market customers for future years. Also covered in this discussion by UNS Gas was the consideration of fully managing the pipeline capacity and scheduling responsibilities, following a corporate review.

I believe the Company is adequately addressing the pipeline capacity and related issues.

Q. Does UNS Gas complete a periodic forecast of system requirements and contract capacity rights?

A. Yes, they do. UNS Gas completes a peak-day forecast for their system at the gate station level. I reviewed that forecast specifically for the April 2004 through March 2005 period and found that the variance between forecast and actual through-put was less than 2% for the 12 months.

Q. What importance does load forecasting have relating to monthly pipeline costs and penalties?

A. Load forecasting plays an increasingly important role in monthly pipeline costs, which the Company recognizes and is addressing. Chiefly due to tariff changes on the EPNG pipeline system, scheduled gas supplies need to be closely in balance to minimize daily costs. Moreover, the Company is also subject to hourly imbalances as well. Therefore, UNS Gas personnel must monitor daily and hourly needs attempting to keep consumption as close to estimated needs as possible.

In the Company's direct testimony, witness David G. Hutchens discusses the EPNG rate case that went into effect in January 2006, subject to refund. Under the pipeline's proposal, daily imbalance penalties would be imposed for variances between daily estimates and actual takes. Thus, the increased importance of load forecasting becomes apparent. UNS Gas will be required to alter their purchasing strategy to minimize this potential increased cost. This will include a higher reliance on hourly and daily system monitoring, frequent load forecasts, and use of spot market gas purchases. Additionally, increased pipeline capacity rights may be required to avoid penalties.

Q. Will these EPNG changes impact UNS Gas in others parts of their organization?

A. Yes, in all likelihood the changes will not only impact the daily functions as discussed above, but may have an impact on the present relationship UNS Gas has with their present supplier, BP. With additional responsibilities shifting to the Company that were once fulfilled by BP, the potential for increased personnel to assume those roles becomes apparent. UNS Gas will need to measure the overall impact of these changes, integrating the operational and personnel impacts into the supplier study I have recommended.

VIII. RECOMMENDATION SUMMARY

Q. Would you please summarize your testimony and recommendations?

A. Yes, I will with the following conclusions:

1. My review of the UNS Gas natural gas procurement, practices, and policies determined that the Company achieved the appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. This finding covers the period of September 2003 through December 2005.

2. In making this above statement, there are a number of improvements which the Company can make when filing the monthly Purchase Gas Adjustor filing which should enhance the Commission's gas cost review process, including:

   a. Copies of EPNG's and Transwestern's monthly Allocation Statements.
   b. Specific hedging detail for each separate supply purchase which appear on the monthly supply invoice.
   c. Written information on the monthly supply invoice(s) identifying each specific purchase (advance hedge).
   d. Automatically submit complete documentation required for Commission Staff to complete a reconciliation of the monthly PGA.

The Commission should require these additions to the PGA filings.

3. NS Gas needs to complete a study of their supply arrangement with BP Energy, where BP acts as an agent and manager of both required supply and transportation responsibilities, to see if continuance is in the best interests of the retail customer from a cost perspective as compared to other suppliers. The Commission would review the findings and conclusions for policy consistency and customer interests.

Q. Does this complete your pre-filed direct testimony?

A. Yes.

GEORGE E. WENNERLYN

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Middleton, Wisconsin 53562
(608) 827-0289 Email: select@itis.com

CAREER SUMMARY

ELECTRIC AND NATURAL GAS UTILITY AND CONSULTING EXECUTIVE with over 35 years of progressive experience in sales/service to the residential, commercial, industrial, institutional, and utility markets

PROFESSIONAL EXPERIENCE

SELECT ENERGY CONSULTING, LLC, Middleton, WI (1996 to present)

A consulting firm formed to work with commercial, institutional, and industrial clients facing the challenges of deregulation in the natural gas markets and seeking new answers in the midst of on going change.

Principal and Owner

Applies first hand knowledge of natural gas supply planning, pricing and the use of hedging techniques, contract development, cost-benefit analysis, and the state and federal regulatory process. Serves as an expert witness to attorneys seeking advice and direction in the areas of natural gas (utility and market rates, gas supply acquisition, pipeline transportation, gas industry regulation and deregulation, pipeline bypass).

A&C ENERCOM CONSULTANTS, INC., Madison, WI (1994 to 1996)

A&C is the nation's largest supplier of energy related services to the electric and gas utility industry. Providing products and services to over 300 utilities and their customers, the company specializes in the areas of utility market program development, energy conservation services, end-use pricing, and project financing.

Director of Operations and Business Consultant

Responsible for the development of new electric and natural gas sales initiatives within the Midwest, working with participating utilities, providing turnkey (Paid From Savings) services to commercial, industrial, and institutional customers. Consulting included providing advice and direction to electric and gas utilities on customer service programs.

WISCONSIN POWER AND LIGHT COMPANY, Madison, WI (1968 to 1994)

WP&L is a major Wisconsin utility providing electric power, natural gas and water service to 330,000 customers in the south central portion of the state, with total revenues of $680 million.

Director of Gas Supply and Gas Pricing (1992 to 1994)

Directed natural gas supply acquisition and customer pricing functions within a rapidly changing marketplace.

Responsible for the purchase of a $65 million gas portfolio annually, achieving the lowest gas acquisition costs among the state utilities served by the major incoming pipeline.
Implemented a new telemeter system with reliability and accuracy objectives achieved on schedule.

Increased industrial gas sales to capture 45% share of the transportation market.

Director of Rate Design and Gas Supply (1989 to 1992)

Responsible for the forecasting of market sales and the pricing of electric, natural gas and water services.

Responsible for the development of demand-side planning analysis for the electric and gas utility.

Implemented a $10 million electric direct load control program on schedule, meeting all sales goals.

Director of Gas Supply and Gas Engineering (1987 to 1989)

Constructed a $5 million pipeline project both on budget and on schedule.

Realigned pre-existing pipeline service contracts, reducing annual contract costs by $6 million, which enhanced the company's competitiveness via alternate source options.

Reduced annual gas costs by 20%

Regional Manager (1981 to 1987)

Managed five district operation centers, comprised of 350 salaried and hourly union represented employees serving 160,000 customers.

Launched the formal process of developing account strategies for the company's major industrial and wholesale customers.

Redirected the field organization's approach to serving its customers through the adoption of service oriented, customer focused principles.

Developed a company wide reporting system to measure cost center performance.

Division Manager (1976 to 1981)

Spearheaded the local public relations effort to construct a major electric generating facility in the area. Appeared before the news media (radio, newspaper, television), community groups, civic leaders, and government/political officials.

Other Positions (1968 to 1976)

Held a number of positions of increasing responsibility including, Accounting and Customer Relations Supervisor, Local Manager, and Manager at various field office locations.

EDUCATION

B.S., Business Administration - University of Minnesota
Post-Graduate Studies in Business and Sales

INDUSTRY RELATED PARTICIPATION

Madison Area Business Consultants
Past-Chairperson for the Wisconsin Distributors Group
Past-Edison Electric Institute Economics Committee
Past-Vice President of the Association of Industry & Manufacturers

Testimony

Wennerlyn, since founding Select Energy Consulting, LLC in 1996, has testified in the following proceedings:

Submitted To:	Subject	Docket No.	Date
Public Utilities Commission of Nevada	Nevada Power Company application to adjust Base Tariff Energy Rate and DEAA case to collect deferred costs (for Bureau of Consumer Protection)	06-01016	2006
Public Utilities Commission of Nevada	Sierra Pacific Power Company application to adjust Base Tariff Energy Rate and DEAA case to collect deferred costs (for Bureau of Consumer Protection)	05-12001	2006
Wisconsin Public Service Commission	WE Energies rate case, natural gas rate design (for Select Energy Consulting, LLC clients)	05-UR-102	2005
Public Utilities Commission of Nevada	Review Sierra Pacific Power Company and Nevada Power Company Energy Supply Plans Update (for Bureau of Consumer Protection)	05-9016 and 05-9017	2005
Public Utilities Commission of Nevada	Review Nevada Power Company's Energy Supply Plan (for Bureau of Consumer Protection)	04-9004	2004
Public Utilities Commission of Nevada	Review Sierra Pacific Power Company's Energy Supply Plan (for Bureau of Consumer Protection)	04-7004	2004
Public Utilities Commission of Nevada	Prudence of Southwest Gas PGA costs, purchase practices (for the PUCN)	03-12012	2004
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate	6690-UR-116	2004

	design issues		
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate design issues	6690-UR-115	2003
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-112	2003
Wisconsin Public Service Commission	Wisconsin Electric Power Company rate case, fuel filing – risk management	6630-UR-111	2003
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-111	2002
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate design issues	6690-UR-113	2001
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate design issues	6690-UR-112	2000
Wisconsin Public Service Commission	Wisconsin Electric Power Company rate case, rate design	6630-UR-111	2000
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-110	2000
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-110	2000

UNS Gas - Monthly WACOG Calculation

Source: from Monthly filed PGA reports and Data Requests BG 3.1 through BG 3.5, and BG 4.1, 4.2, 4.11, and 4.13
Note: "Retail" here means the gas cost for a retail customer, at the point of purchase. It does not signify cost at either the city-gate or the burnertip.

		From PGA monthly reports			From Supply Basin Mix Report:			Basin Market Price (first of the month) Comparisons to UNS Retail Price:						Results:		
Month	Year	Retail Commodity Only Gas Cost	Retail Purchase Volumes Dths	Retail Commodity Only $/Dth	FOM SanJuan Volumes	FOM Permian Volumes	FOM Waha Volumes	San Juan FOM Price	Permian FOM Price	Waha FOM Price	Market WACOG FOM Price (Basin weighted)	Variance Retail above Market ($ per dth)	Variance Retail above Market (%)	Monthly Variance Retail Commodity above Market	To-date Retail Commodity above Market Commodity	Annual To-date Retail Commodity above Market Commodity
Sep	2003	$ 1,685,734	337,804	$ 4.99	[redacted]	[redacted]	[redacted]	$ 4.44	$ 4.77	$ -	[redacted]	$ 0.55	12.4%	$ 185,884	$ 185,884	$ 185,884
Oct	2003	$ 2,383,376	476,796	$ 5.00	[redacted]	[redacted]	[redacted]	$ 3.95	$ 4.14	$ -	[redacted]	$ 1.05	26.6%	$ 500,032	$ 685,916	$ 685,916
Nov	2003	$ 6,160,289	1,352,365	$ 4.56	[redacted]	[redacted]	[redacted]	$ 3.96	$ 4.07	$ -	[redacted]	$ 0.60	15.0%	$ 804,924	$ 1,490,840	$ 1,490,840
Dec	2003	$ 8,691,238	1,789,037	$ 4.86	[redacted]	[redacted]	[redacted]	$ 4.23	$ 4.36	$ -	[redacted]	$ 0.63	14.8%	$ 1,123,611	$ 2,614,451	$ 2,614,451
Jan	2004	$ 10,304,726	1,933,619	$ 5.33	[redacted]	[redacted]	[redacted]	$ 5.13	$ 5.40	$ -	[redacted]	$ 0.20	3.9%	$ 382,241	$ 2,996,692	$ 382,241
Feb	2004	$ 9,375,716	1,812,765	$ 5.17	[redacted]	[redacted]	[redacted]	$ 5.01	$ 5.13	$ -	[redacted]	$ 0.16	3.2%	$ 292,834	$ 3,289,526	$ 675,074
Mar	2004	$ 4,609,917	914,202	$ 5.04	[redacted]	[redacted]	[redacted]	$ 4.40	$ 4.53	$ -	[redacted]	$ 0.64	14.6%	$ 587,428	$ 3,876,954	$ 1,262,503
Apr	2004	$ 3,764,404	798,592	$ 4.71	[redacted]	[redacted]	[redacted]	$ 4.46	$ 4.67	$ -	[redacted]	$ 0.25	5.7%	$ 202,637	$ 4,079,590	$ 1,465,139
May	2004	$ 2,275,120	451,737	$ 5.04	[redacted]	[redacted]	[redacted]	$ 5.06	$ 5.32	$ -	[redacted]	$ (0.02)	-0.5%	$ (10,669)	$ 4,068,921	$ 1,454,470
Jun	2004	$ 1,972,107	365,752	$ 5.39	[redacted]	[redacted]	[redacted]	$ 5.71	$ 6.19	$ -	[redacted]	$ (0.32)	-5.6%	$ (116,337)	$ 3,952,584	$ 1,338,133
Jul	2004	$ 1,884,910	348,413	$ 5.41	[redacted]	[redacted]	[redacted]	$ 5.49	$ 5.94	$ -	[redacted]	$ (0.08)	-1.5%	$ (27,877)	$ 3,924,707	$ 1,310,256
Aug	2004	$ 1,920,143	350,578	$ 5.48	[redacted]	[redacted]	[redacted]	$ 5.39	$ 5.68	$ -	[redacted]	$ 0.09	1.6%	$ 30,528	$ 3,955,234	$ 1,340,783
Sep	2004	$ 1,986,737	394,000	$ 5.04	[redacted]	[redacted]	[redacted]	$ 4.56	$ 4.72	$ -	[redacted]	$ 0.48	10.6%	$ 190,097	$ 4,145,331	$ 1,530,880
Oct	2004	$ 3,811,869	773,184	$ 4.93	[redacted]	[redacted]	[redacted]	$ 4.47	$ 4.59	$ 5.37	[redacted]	$ 0.44	9.9%	$ 342,743	$ 4,488,075	$ 1,873,623
Nov	2004	$ 9,760,850	1,502,184	$ 6.50	[redacted]	[redacted]	[redacted]	$ 6.90	$ 6.94	$ 6.94	[redacted]	$ (0.41)	-5.9%	$ (611,268)	$ 3,876,807	$ 1,262,356
Dec	2004	$ 11,444,743	1,937,883	$ 5.91	[redacted]	[redacted]	[redacted]	$ 5.95	$ 6.17	$ -	[redacted]	$ (0.05)	-0.9%	$ (105,005)	$ 3,771,802	$ 1,157,351
Jan	2005	$ 10,709,176	1,847,191	$ 5.80	[redacted]	[redacted]	[redacted]	$ 5.67	$ 5.58	$ -	[redacted]	$ 0.13	2.3%	$ 241,044	$ 4,012,846	$ 241,044
Feb	2005	$ 8,756,758	1,531,933	$ 5.72	[redacted]	[redacted]	[redacted]	$ 5.43	$ 5.53	$ -	[redacted]	$ 0.29	5.3%	$ 437,760	$ 4,450,606	$ 678,805
Mar	2005	$ 7,808,477	1,403,641	$ 5.56	[redacted]	[redacted]	[redacted]	$ 5.21	$ 5.54	$ -	[redacted]	$ 0.35	6.7%	$ 491,352	$ 4,941,958	$ 1,170,157
Apr	2005	$ 5,178,267	890,909	$ 5.81	[redacted]	[redacted]	[redacted]	$ 6.21	$ 6.37	$ -	[redacted]	$ (0.40)	-6.4%	$ (354,278)	$ 4,587,681	$ 815,879
May	2005	$ 3,110,406	541,991	$ 5.74	[redacted]	[redacted]	[redacted]	$ 6.30	$ 6.27	$ -	[redacted]	$ (0.56)	-8.9%	$ (304,137)	$ 4,283,543	$ 511,741
Jun	2005	$ 2,150,224	394,206	$ 5.45	[redacted]	[redacted]	[redacted]	$ 5.38	$ 5.66	$ -	[redacted]	$ 0.07	1.4%	$ 29,396	$ 4,312,939	$ 541,137
Jul	2005	$ 2,063,377	350,085	$ 5.89	[redacted]	[redacted]	[redacted]	$ 6.05	$ 6.71	$ -	[redacted]	$ (0.16)	-2.6%	$ (54,637)	$ 4,258,302	$ 486,500
Aug	2005	$ 2,376,435	361,674	$ 6.57	[redacted]	[redacted]	[redacted]	$ 5.97	$ 6.76	$ -	[redacted]	$ 0.60	10.1%	$ 217,241	$ 4,475,543	$ 703,741
Sep	2005	$ 2,820,039	384,556	$ 7.33	[redacted]	[redacted]	[redacted]	$ 8.03	$ 8.61	$ -	[redacted]	$ (0.70)	-8.7%	$ (268,001)	$ 4,207,542	$ 435,740
Oct	2005	$ 5,202,655	632,750	$ 8.22	[redacted]	[redacted]	[redacted]	$ 9.52	$ 9.80	$ 10.11	[redacted]	$ (1.31)	-13.7%	$ (826,205)	$ 3,381,337	$ (390,465)
Nov	2005	$ 8,879,039	1,171,200	$ 7.58	[redacted]	[redacted]	[redacted]	$ 10.82	$ 10.75	$ 11.40	[redacted]	$ (3.25)	-30.0%	$ (3,803,054)	$ (421,717)	$ (4,193,518)
Dec	2005	$ 15,073,197	1,843,808	$ 8.18	[redacted]	[redacted]	[redacted]	$ 8.11	$ 8.45	$ -	[redacted]	$ 0.06	0.7%	$ 105,237	$ (316,480)	$ (4,088,282)

	Commodity cost	% variance
Total for entire period	$ 156,159,929	-0.2%
Year 2005	$ 74,128,050	-5.5%
Year 2004	$ 63,111,242	1.8%
Balance 2003	$ 18,920,637	13.8%

Variance	
$ (316,480)	Total for entire period
$ (4,088,282)	Year 2005
$ 1,157,351	Year 2004
$ 2,614,451	Balance 2003

Note:
Negative number is below market or less than
Positive number is above market or more than

UNS Gas, Inc. 36-Month Ranking Analysis
Compares the High, Low, and Actual Purchase Price (NYMEX Equivalent)
Covers the period of September 2004 through December 2005

Delivery Month	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Total
High price purchase value									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Low price purchase value									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Actual purchase value									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ranking	no review	no review	no review	no review	no review	no review	no review	no review	70%	70%	31%	60%	55%
Volume Delivered									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36-Month High Price									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36-Month Low Price									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Price Actual									[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Delivery Month	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
High price purchase value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Low price purchase value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Actual purchase value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ranking	56%	56%	39%	80%	81%	66%	64%	75%	76%	76%	55%	50%	56%
Volume Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36-Month High Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36-Month Low Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Price Actual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Delivery Month	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
High price purchase value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Low price purchase value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Actual purchase value	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ranking	50%	50%	51%	52%	48%	47%	46%	38%	25%	17%	17%	25%	37%
Volume Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36-Month High Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36-Month Low Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Price Actual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

UNS Gas, Inc. 36-Month Ranking Analysis
Compares the High, Low, and Actual Purchase Price (NYMEX Equivalent)
Covers the period of September 2004 through December 2005

Annual Results

Delivery Year	2003* (note: partial year)	2004	2005	Total
High price purchase value	[redacted]			
Low price purchase value				
Actual purchase value				
Ranking	55%	56%	37%	46%
Volume Delivered	[redacted]			
36-Month High Price	[redacted]			
36-Month Low Price				
Average Price Actual				

REDACTED

DIRECT TESTIMONY OF

JERRY MENDL (CONSULTANT)

DOCKET NOS. G-04204A-06-0463

G-04204A-06-0013

&

G-04204A-05-0831

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA

FEBRUARY 16, 2007

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	)	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	)	DOCKET NO. G-04204A-05-0831

REDACTED

DIRECT

TESTIMONY

OF

JERRY E. MENDL

ON BEHALF OF

ARIZONA CORPORATION COMMISSION STAFF

FEBRUARY 16, 2007

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EXHIBITS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463 ET AL

UNS Gas' procurement strategy over the September 2003 through December 2005 transition period, as set out in its January 1, 2005 price stabilization policy and utilizing low cost hedging instruments, was reasonable.

- The 2005 price stabilization policy, when fully implemented would spread purchases out over a three-year period.
- Fixed price forward physical gas contracts is the primary method identified in the policy to stabilize prices.
- Call options and collars, which incur premiums that may not be cost effective for ratepayers, were allowed under the Policy but not actually used in the audit period.

The use of hedging instruments incurring large premiums to help stabilize retail prices will not be reasonable unless the prices are not sufficiently stabilized by the regulatory process and low cost hedges.

- Over-and under-collections are banked and periodically reallocated, thus dampening the price volatility actually experienced by ratepayers.
- The PGA rates are based on a 12-month rolling average of the costs, thus dampening the price volatility actually experienced by ratepayers.
- Hedging instruments, such as physical fixed price forward contracts, reduce ratepayer price volatility without adding to ratepayer cost.
- Going forward, UNS Gas should factor in the potential for imbalance penalties associated with the recently implemented hourly balancing mechanism when considering modifications to its Price Stabilization Policy.

The changes to UNS Gas' fully implemented procurement strategy over a 36-month period, as set out in its January 1, 2006 price stabilization policy, appear to be reasonable if UNS Gas continues to utilize low cost hedging instruments.

- Like the 2005 Price Stabilization Policy, the 2006 Price Stabilization Policy would spread purchases out over a three-year period, use fixed price forward physical contracts as the primary method, and would allow call options and collars.
- The purchase timing under 2006 Price Stabilization Policy, when fully implemented, appears reasonable when the fixed price forward physical contracts are used, but may incur costs not commensurate with the benefits to ratepayers if call options or collars are used.

UNS Gas concentrated its gas purchases into only a few days, which results in higher risk of undue gas cost volatility.

- UNS Gas did not precisely carry out its 2005 Price Stabilization Policy.
- All the fixed price gas delivered during the 28-month audit period was purchased on only 20 days.

The impact of UNS Gas' concentrated procurement practices on actual cost was small, less than 2%.

- Had UNS Gas exactly followed its Price Stabilization Policy, the NYMEX cost of gas would have been slightly less than the NYMEX cost of gas under its actual purchase timing.
- Had UNS Gas followed a uniform dollar cost averaging strategy (for each delivery month, purchasing equal volumes of gas in each available purchase month), the NYMEX cost of gas would have been less than the NYMEX cost of gas under its actual purchase timing, but more than under its Price Stabilization Policy.

The Commission should not approve UNS Gas' request to approve its 2006 Gas Price Stabilization Policy.

- The 2006 Price Stabilization Policy would allow UNS Gas to stabilize prices using call options and collars which could add to the cost without commensurate benefit to ratepayers.
- Approval of the Policy would create a safe harbor that would increase the resistance of UNS Gas to change policies when conditions warranted.
- If the Commission considers approving the Price Stabilization Policy, it should require UNS Gas to provide a detailed explanation of how it would monitor the markets and make changes for the ratepayers' benefit.
- If the Commission considers approving the Price Stabilization Policy, it should condition the approval to be valid only as long as the conditions underlying the policy are valid.
- If the Commission considers approving the Price Stabilization Policy, it should require UNS Gas to show that any premiums anticipated for hedging instruments are reasonable and serve the objectives of stabilizing prices while minimizing costs.
- If the Commission considers approving the Price Stabilization Policy, it should require UNS Gas to provide a corrected copy of the Policy.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jerry E. Mendl. I am the President of MSB Energy Associates, Inc. ("MSB"). My business address is MSB Energy Associates, Inc., 7507 Hubbard Avenue, Middleton, Wisconsin 53562.

Q. Does Exhibit JEM-1 summarize your qualifications?

A. Yes.

Q. What is the purpose of your testimony?

A. Together with Mr. George E. Wennerlyn, a subcontractor to MSB, I am appearing on behalf of the Staff of the Arizona Corporation Commission - Utilities Division to address the prudence of UNS Gas, Inc.'s ("UNS Gas") gas procurement practices over the time frame spanning September 2003 through December 2005. My testimony focuses on the timing of gas purchases by UNS Gas relative to its Price Stabilization Policy. I also address UNS Gas' request that the Commission approve UNS Gas' Price Stabilization Policy.

FINDINGS AND RECOMMENDATIONS

Q. What are your findings?

A. In my review of UNS Gas' gas procurement practices, I concluded:

1. UNS Gas' procurement strategy over the September 2003 through December 2005 transition period, as set out in its January 1, 2005 price stabilization policy and utilizing low cost hedging instruments, was reasonable.

2. The use of hedging instruments incurring large premiums to help stabilize retail prices will not be reasonable unless the prices are not sufficiently stabilized by the regulatory process and low cost hedges.
3. The changes to UNS Gas' fully implemented procurement strategy over a 36-month period, as set out in its January 1, 2006 price stabilization policy, appear to be reasonable if UNS Gas continues to utilize low cost hedging instruments.
4. UNS Gas concentrated its gas purchases into only a few days, which results in higher risk of undue gas cost volatility.
5. The impact of UNS Gas' concentrated procurement practices on actual cost was small, less than 2%.
6. The Commission should not approve UNS Gas' request to approve its 2006 Price Stabilization Policy.

2005 PRICE STABILIZATION POLICY

I. UNS Gas' procurement strategy over the September 2003 through December 2005 transition period, as set out in its January 1, 2005 price stabilization policy and utilizing low cost hedging instruments, was reasonable.

Q. Did UNS Gas have a written policy regarding gas procurement that applied to the September 2003 - December 2005 period?

A. Yes, UNS Gas had its Price Stabilization Policy effective January 1, 2005, that set out the objectives for purchasing fixed price gas in order to maintain stable gas prices to ratepayers. UNS Gas ensured that the policy was implemented by requiring responsible employees to agree to comply with the parameters of the Price Stabilization Policy, and acknowledge that the willful violation of the limits set in the Price Stabilization Policy may result in disciplinary action. In my opinion, UNS Gas placed strong emphasis on ensuring that the Price Stabilization Policy was appropriately implemented.

Q. What was UNS Gas' price stabilization policy that applied to the September 2003 - December 2005 period?

A. The UNS Gas Price Stabilization Policy that was effective January 1, 2005 applied to this period. It called for 45% of the estimated monthly gas load to be supplied through non-discretionary purchases of fixed price gas. The non-discretionary purchases were to be made over a three year period prior to the delivery month, using calendar triggers on approximately January 19, March 9, and July 19. Thus for each delivery month, there should be nine purchase dates for fixed price non-discretionary gas, with each purchase being 5% of the estimated monthly gas load.

In addition, the Price Stabilization Policy also allowed UNS Gas to purchase discretionary gas volumes over and above the non-discretionary amounts when favorable purchasing opportunities exist. The sum of the discretionary and non-discretionary volumes were limited to 80% of the estimated monthly gas load to allow the opportunity for some index purchasing and to provide a buffer against abnormally low loads.

PURPOSE OF THE PRICE STABILIZATION POLICY

Q. What is the purpose of the company's price stabilization policy?

A. As its name states, the purpose of the policy is to stabilize the prices UNS Gas, and ultimately its customers, pay for natural gas through forward hedging activities.

Q. What hedging mechanisms are available to UNS Gas under its stabilization policy?

A. UNS Gas relies on fixed price forward physical purchases as its primary method to stabilize prices as well as NYMEX purchases, call options and collars as its secondary methods.

Q. Will employing a hedging strategy reduce the company's gas costs?

A. No, on average, hedging strategies will increase the cost of gas. The purpose of hedging strategies is to stabilize the cost of gas - to dampen the effects of gas price volatility. Depending on the hedging strategy used, the Company may incur a significant premium on the price to limit the price risk.

At one extreme, a utility could purchase all of its natural gas requirements on the spot market, or at the first of the month index price. Changes in short-term natural gas market conditions could result in volatile price swings and costs to the utility. The purpose of hedging is to dampen or avoid this price risk.

The utility can reduce the price risk by purchasing some of the gas supply under fixed price forward physical contracts, which is UNS Gas' primary price stabilization method. Using this method, UNS Gas would lock into physical supply on a predetermined schedule over a 36-month period in advance of delivery. Once UNS Gas makes the forward fixed price purchase, the price is locked and that volume of gas is no longer subject to price risk. Using this method, UNS Gas does not pay an explicit premium for its protection against price increases. But UNS Gas retains the risk that if gas market prices drop, it will end up paying above-market prices for the volumes of gas purchased this way. In times of increasing market price trends, fixing prices over a three-year period will tend to reduce average costs. Conversely, in a time of decreasing market prices, purchasing fixed price forward contracts will tend to result in higher average costs.

The utility can also shed price risk by purchasing call options or collars from a third party. In these financial transactions, the third party assumes the risk that prices will rise above some strike price. The utility will pay no more than the strike price for natural gas hedged in that way, but the utility will pay a premium to the third party for absorbing the risk that it will go higher than the strike price. For the third party to be willing to assume the risk and to stay in business, the premium on average must be sufficient to pay for the times that the market price exceeds the strike price and to generate a profit for the investors. It follows that the more volatile the gas market is perceived to be, the higher the premium. Thus, on average, the premium will add to the cost of gas.

PRUDENCE OF THE PRICE STABILIZATION EXPENDITURES

II. The use of hedging instruments incurring large premiums to help stabilize retail prices will not be reasonable unless the prices are not sufficiently stabilized by the regulatory process and low cost hedges.

Q. Is it prudent and reasonable for UNS Gas to incur a premium that increases the cost of gas in order to reduce price volatility?

A. From a ratepayer perspective, a large premium may not be justified. There are at least three factors that must be weighed to determine how much expenditure is appropriate to control retail price (rate) volatility.

First, the regulatory process itself stabilizes prices paid by UNS Gas ratepayers. The fact that over- and under-collections are banked and redistributed periodically stabilizes the rates paid by retail gas customers. In addition, the PGA is based on a 12-month rolling average of gas costs rather than the most current monthly gas cost. This method of calculating the PGA rate dampens month to month price volatility in the rates as paid by the ratepayers. The regulatory process stabilizes retail rates experienced by UNS Gas' customers, but does not reduce the volatility of costs paid by UNS Gas.

Second, UNS Gas can purchase physical gas through fixed price forward contracts as it had done during the audit period. This approach reduces the volatility of costs paid by UNS Gas, which in turn reduces the rate volatility experienced by UNS Gas' customers. It reduces retail price volatility without an added premium to increase cost.

Third, UNS Gas could stabilize prices by purchasing financial gas - such as call options - to limit the price paid for gas. In addition to the market price of physical gas, UNS Gas may incur premiums that significantly add to the cost of gas. For its customers, these premiums may secure instruments that reduce rate volatility, but will increase overall rates.

If the first and second factors adequately address rate volatility from a ratepayer perspective, it is not reasonable to require ratepayers to pay a premium to further stabilize retail rates.

Q. Are there some conditions under which purchasing financial gas and incurring a premium could be prudent and reasonable?

A. Yes, there could be. For example, if there were an insufficient number of bidders willing to provide physical gas under fixed price forward contracts, competitive prices might not result. Supplementing those bids for physical gas with more liquid financial gas instruments could bring overall gas cost down.

As another example, beyond the audit period El Paso's hourly balancing requirement has taken effect. As UNS Gas considers the potential imbalance penalties, it may be appropriate to modify the current hedging target of 45% of monthly gas demand. UNS Gas should also assess whether fixed price three year forward physical gas contracts are sufficiently flexible to meet that target in light of the potential impact of penalties incurred under El Paso's daily balancing requirement. Financial gas instruments could play a role, especially if the cost of the premiums declines.

In general, if the rate volatility cannot be sufficiently controlled through the ratemaking process and low cost hedges, then higher cost hedges with significant premiums may be needed to balance the objectives of stabilizing rates and minimizing cost.

Q. Are you suggesting that UNS Gas' price stabilization expenditures were imprudent?

A. No. UNS Gas' Price Stabilization Policy relies primarily on fixed price forward contracts. Our audit showed that UNS Gas has not incurred any hedging premiums. I would be concerned if UNS Gas began relying on call options and collars and began to incur premiums, but that has not been the case in the September 2003 through December 2005 audit period.

Later in my testimony, I will report on the prices faced by UNS Gas under its procurement strategy compared to other strategies it may have pursued. Mr. Wennerlyn and I have concluded that the cost of gas actually paid by UNS Gas for the audit period was reasonable in comparison to market prices.

Q. Please summarize.

A. During the audit period, UNS Gas implemented its 2005 Price Stabilization Policy by using low cost hedging instruments to control retail price volatility. It resulted in a reasonable cost of gas. Had UNS Gas used high cost (expensive premiums) hedging instruments, it could have resulted in an unreasonable cost of gas.

Beyond the audit period, UNS Gas implemented its 2006 Price Stabilization Policy. In addition, beyond the audit period the El Paso transportation service tariff now calls for hourly balancing. Going forward, UNS Gas should factor in the potential for imbalance penalties in assessing further modifications to its 2006 Price Stabilization Policy, both in regard to the hedged fraction and the hedging instruments.

2006 PRICE STABILIZATION POLICY

III. The changes to UNS Gas' fully implemented procurement strategy over a 36-month period, as set out in its January 1, 2006 price stabilization policy, appear to be reasonable if UNS Gas continues to utilize low cost hedging instruments.

Q. What changes is UNS Gas implementing in its new gas price stabilization policy which became effective on January 1, 2006?

A. UNS Gas has modified its Gas Price Stabilization Policy to utilize monthly calendar triggers for its non-discretionary purchases, excluding the months of August through October because of historical volatility due to hurricanes. The 2006 Policy still retains the non-discretionary target of 45% of the estimated monthly gas load. In effect, the policy change increases the number of purchase dates for non-discretionary fixed price gas from three per year (January, March and July) to nine per year (all but August - October). Non-discretionary fixed price gas prices would be averaged over 27 purchases spread over three years under the 2006 Price Stabilization Policy instead of 9 purchases over three years under the 2005 Policy.

Q. Is the 2006 price stabilization policy an improvement over the 2005 policy?

A. In a theoretical sense, I believe it provides more price stability by averaging costs over more purchase dates. Thus, it should show less fluctuation. That is consistent with the analysis reported in Exhibit JEM-5 which "backcasted" the effect of the 2006 and 2005

Price Stabilization Policies on NYMEX cost given the NYMEX prices from September 2000 through December 2005. The analysis does not suggest that the new approach will yield materially different gas costs. Nonetheless, the revised 2006 Price Stabilization Policy more closely approximates pure dollar cost averaging, which is a recognized method to reduce price volatility.

Q. Once the new 2006 price stabilization policy becomes fully implemented in approximately three years, will it set reasonable procurement parameters?

A. The indications are that it will. Exhibit JEM-4 "backcasts" the fully implemented 2005 Stabilization Policy and the three-year uniform implementation scenario based on NYMEX prices from September 2000 (three years prior to the beginning of the audit period) through December 2005. The new 2006 Price Stabilization Policy is nearer to the uniform three-year dollar cost averaging standard, and thus would likely to have been close to that result. In my opinion, the new policy is likely to set reasonable procurement parameters regarding timing.

This presumes that UNS Gas continues to purchase fixed price forward physical supply as its primary method to stabilize prices. I do not believe the new policy would set reasonable procurement parameters if UNS Gas began to purchase call options or collars that incur costs for premiums. The risk premiums tend to increase as the coverage period gets longer. Thus, while a three-year time frame is quite reasonable for fixed price forward purchases, the three-year time frame is likely to be too long for a call option because the premium becomes very expensive.

One additional caveat about my conclusion that the 2006 Policy is likely to set reasonable procurement parameters - my focus was on timing of the purchases and does not account for the potential impact of imbalance penalties on the amount of gas hedged and instruments used to hedge it.

ACTUAL TIMING OF UNS GAS PURCHASES

IV. UNS Gas concentrated its gas purchases into only a few days, which results in higher risk of undue gas cost volatility.

Q. In light of its price stabilization policy, what was the timing of UNS Gas' natural gas purchases during the audit period?

A. The purchases were quite concentrated in time, which leads to a higher risk of undue gas cost volatility.

CONCENTRATION OF PURCHASES

Q. Why does concentrating gas purchases into relatively few days result in higher risk of undue gas cost volatility?

A. Natural gas prices can vary greatly from day to day. In recent years, natural gas prices have been highly volatile, particularly as extreme weather increases the demand for gas and as production capability is vulnerable to interruption due to hurricanes. Concentrating purchases into relatively few days takes the risk that gas prices will be higher than average on the dates of purchase, which increases the volatility of gas costs paid by ratepayers. If the gas supplies for each delivery month are purchased on one day, gas cost will be as volatile as the gas prices. If the gas supplies for each delivery month are purchased over many days, and particularly over a longer period of time, the weighted cost of gas for the delivery month will be stabilized. As a general principle, the more days over a longer time frame that natural gas is purchased, the more stable will be its average price and cost to the ratepayers.

Q. How concentrated were the purchases of natural gas for delivery in the September 2003 - December 2005 period?

A. Approximately 60% of the natural gas delivered to UNS Gas during the September 2003-December 2005 time frame was purchased under fixed price contracts. The rest was purchased under index priced contracts (first of month index) or daily index or the spot market.

All of the fixed-price natural gas for delivery in that 28-month period was purchased on just 20 days. Some of the gas was purchased by Citizens prior to September 2003, when UNS Gas took over the utility. Citizens purchased gas for the period on 6 of the 20 days, while UNS Gas purchased gas on 14 days. The table below shows the distribution of gas purchased on the 20 days. Not only was all of the fixed price gas purchased over just a few days, the volumes purchased on each of those days varied from 1% to 19% of the period volume.

In my opinion, these fixed price purchases are quite concentrated, and as such, pose a significant risk that natural gas prices will be relatively high at the time of purchase, thus increasing the gas cost volatility.

Date of gas purchase for delivery in the September 2003 - December 2005 period	% of period fixed-price gas purchased by Citizens and UNS Gas	% of period fixed-price gas purchased by UNS Gas
[redacted]	3%	
	5%	
	7%	
	3%	
	3%	
	1%	
	7%	9%
	4%	5%
	5%	7%
	13%	17%
	14%	18%
	1%	1%
	1%	2%
	19%	24%
	5%	7%
	1%	2%
	3%	4%
	1%	2%
	1%	2%
	1%	1%

CONSISTENCY OF PURCHASE TIMING WITH PRICE STABILIZATION POLICY

Q. Did UNS Gas follow its 2005 price stabilization policy regarding the purchase schedules for fixed price gas?

A. Not exactly. It is clear from the preceding table that purchases did not always occur in the designated months of January, March and July, nor on the designated calendar date triggers in those months. The actual purchase volumes do not appear to be evenly distributed among the purchase dates, though that may be partially explained by UNS Gas' purchase of some discretionary gas volumes as well.

However, there are extenuating circumstances that must be considered. First, when UNS Gas took over the utility from Citizens in September 2003, Citizens had already purchased some of the fixed price gas for delivery months through July 2004. UNS Gas did not have to make a non-discretionary purchase until April 2004, although it made some discretionary purchases beginning in November 2003.

In addition, UNS Gas' Price Stabilization Policy would take three years to fully implement. Exactly following the policy would mean that the first non-discretionary purchase date following the September 2003 date when UNS Gas took ownership would be approximately January 19, 2004 for delivery beginning February 2004. The procurement policy could not be fully implemented to provide nine non-discretionary fixed-price purchases until July 2006 for gas to be delivered in August 2006, at earliest. Until then, the implementation of the Price Stabilization Policy would be in transition.

Q. Was UNS Gas' price stabilization policy or its implementation of the policy unreasonable?

A. While there are a myriad of ways in which UNS Gas could have procured gas, my conclusion is that the method used by UNS Gas did not produce an unreasonable outcome. I examined the purchase timing issue in some detail, and reached conclusions similar to Mr. Wennerlyn.

IMPACT OF PROCUREMENT TIMING ON GAS COST

V. The impact of UNS Gas' concentrated procurement practices on actual cost was small, less than 2%.

Q. How should the Commission consider your conclusion that UNS Gas deviated from its price stabilization policy?

A. There is a tradeoff that must be recognized whenever a policy of this sort is implemented. The policy provides guidance and discipline to gas purchasing. Without it, a utility may elect not to purchase gas because prices were higher than anticipated, but then find that the prices rose even more before it eventually made the purchase. Discipline is important to achieving stable gas prices (and costs) because it ensures that gas is purchased over time to result in a more stable weighted cost of gas. Failure to follow policy may be imprudent. On the other hand, blind adherence to a policy in light of changing market conditions can result in excess and unreasonable gas costs.

Even if a utility did not have a gas procurement policy or would deviate from its gas procurement policy, it may still end up with reasonable costs. In such an instance, the Commission may wish to address a more reasonable procurement method, and perhaps condition its order to improve the utility's procurement practices, but it may still find the costs to be prudent and reasonable.

METHOD OF ANALYSIS

Q. What analysis did you perform to determine whether the outcome of UNS Gas' gas procurement was reasonable gas cost?

A. First, I examined when UNS Gas (and Citizens before it) purchased gas for each delivery month in the September 2003 - December 2005 delivery period as a function of the three-year gas contract price history for that delivery month. This is an expansion of Mr. Wennerlyn's gas price ranking that shows not only the high and low prices but the daily prices. This provides information as to the likelihood that a lower cost scenario could exist. For example, if UNS Gas actually bought substantial amounts of gas on relatively high priced days, it might suggest that buying gas exactly according to the stabilization policy, or some other policy, could result in lower costs.

Second, I examined some scenarios for gas procurement to see how the gas costs for the September 2003 - December 2005 delivery period would have compared to the actual costs.

Q. What did you conclude from your assessment of the purchase history?

A. I produced a series of graphs depicting the three-year price histories relative to the actual fixed price purchases for each delivery month. Generally speaking, the graphs show UNS Gas and Citizens purchased its gas on a limited number of days generally near the recent end of the gas price history. The price graph shows that gas prices have increased over the three-year historical period. Since actual purchases were made over the more recent months, it follows that the gas costs would have been lower had the purchases been made over the entire three-year period. However, it is not reasonable to hold UNS Gas accountable for purchases made or not made prior to September 2003, the date when UNS Gas acquired the gas utility from Citizens.

In addition, at certain times, gas prices in the monthly price histories showed a decline, at least for a while. In those instances, purchasing more gas in the near term would be less costly than spreading those purchases out over the entire three-year period.

The graphs for each month are attached in Exhibit JEM-2. As can be seen in Exhibit JEM-2, there are a number of opportunities for UNS Gas to have purchased more or less gas at times when prices were relatively lower or higher, respectively. Since one does not have the benefit of 20-20 hindsight when the purchases are being made, it would not be appropriate to compare the actual cost to what the cost could have been with perfect knowledge. However, it is appropriate to compare the actual costs to what the costs would have been had UNS Gas exactly followed its Price Stabilization Policy or to an alternative uniform purchase timing strategy.

PURCHASE TIMING ALTERNATIVES ANALYZED

Q. What analyses have you done to determine the cost impacts of another procurement timing strategy, or not deviating from the procurement strategy set out in the 2005 price stabilization policy?

A. Since one cannot know in advance what the prices will be at any particular future date, I analyzed what the gas costs would have been under several procurement timing scenarios. To keep the costs comparable, I calculated the NYMEX gas cost for the volumes and dates for each scenario. I examined the following scenarios:

1. The actual purchase timing used by Citizens and UNS Gas for fixed price gas for delivery in the September 2003 - December 2005 period.
2. Uniform purchase timing over the full three years in advance of delivery. This assumes that UNS Gas would have acquired the same volume of fixed price gas, but in 36 equal monthly purchases prior to each delivery month. This is the

ultimate dollar cost averaging scenario, but not actually available to UNS Gas during the audit period because it includes purchase months before September 2003 when UNS Gas acquired the gas utility.

3. Full implementation of UNS Gas' three-year purchase horizon using the schedule set out in the 2005 Price Stabilization Policy. In this scenario, the same amount of fixed-price gas was assumed to have been purchased, but in nine equal installments occurring on the trade dates nearest to January 19, March 9 and July 19 in the three years prior to the delivery month. This full implementation scenario was also not actually available to UNS Gas during the audit period because it includes purchase months before September 2003 when UNS Gas acquired the gas utility.

These scenarios compare the fixed price NYMEX gas cost under fully implemented three-year procurement practices to the NYMEX gas cost as actually procured. They help analyze the merit of the Price Stabilization Policy once it can be fully implemented.

Q. Did you examine any other scenarios?

A. Yes. While the fully-implemented scenarios above provide insights about the steady state operation of the Price Stabilization Policy, the fact is that the current period, September 2003 - December 2005, is entirely a transition period. At no time during this period could the Price Stabilization Policy have been fully implemented. Thus I considered three transition scenarios designed to procure gas during the transition. In each transition scenario, I considered the fact that UNS Gas had no control over the purchases already made by Citizens for the September 2003 - December 2005 audit period. I also considered that UNS Gas could not purchase gas prior to September 2003, and thus ramped up purchases to match those actually made by UNS Gas as quickly as possible in equal monthly amounts during the months in which purchases would be made under the policy. I examined the following transition scenarios:

1. Uniform purchase timing every month available after September 2003 until the month prior to delivery. For example, UNS Gas actually purchased some fixed price gas for delivery in December 2003. In this scenario, I assumed that UNS Gas purchased the same amount of fixed price gas for delivery in December 2003, but split equally over three months (September, October and November 2003).
2. UNS Gas 2005 Policy purchase timing, assuming that UNS Gas bought the same volumes of fixed price gas as soon as it could under the 2005 Price Stabilization Policy.
3. UNS Gas 2006 Policy purchase timing, assuming that UNS Gas bought the same volumes of fixed price gas as soon as it could under the revised 2006 Price Stabilization Policy that became effective on January 1, 2006. While outside of the audit period, this scenario provides insights about the effectiveness of the new policy - had it been implemented sooner.

RESULTS OF ANALYSIS

Q. What did your analysis show?

A. My analysis showed that a fully implemented strategy, spreading purchases over a three-year period, would have resulted in lower NYMEX costs for the same amounts of fixed price gas that was actually purchased. My analysis also showed that it did not make much difference whether the purchasing strategy was 36 equal monthly purchases over three years or the nine equal monthly purchases on the three calendar triggers per year specified in the 2005 Price Stabilization Policy. This is the result of lowering the average price of gas by including more of the early months when the gas prices were lower, as can be seen in Exhibit JEM-2.

My analysis shows that for the equivalent volumes of fixed price gas, the three-year uniform scenario would have provided the gas at a 17% lower NYMEX cost than the actual purchases. The fully-implemented three-year 2005 Price Stabilization Policy scenario would have provided gas at a NYMEX cost 18% lower than the actual. Supplying the gas under a uniform transition scenario would have resulted in 0.6% lower NYMEX cost. Using the UNS Gas Transition 2005 Price Stabilization Policy scenario would have saved about 2% on NYMEX gas costs. The new UNS Gas Transition 2006 Price Stabilization Policy scenario would have saved about 2.3% on NYMEX gas costs, only slightly more savings than the Policy in effect during the audit period. These results are shown in Exhibit JEM-3.

Exhibit JEM-4 shows the cumulative NYMEX cost savings of the fully implemented three-year purchase timing strategies over the audit period. Both the uniform three-year scenario and the UNS Gas 2005 Plan three-year scenario would have saved around $18 million relative to the actual fixed price gas purchases. I did this analysis to examine how the 2005 Policy would have performed relative to the uniform strategy, if either could have been fully implemented. It shows that a fully implemented 2005 Policy would have performed well over the audit period. It also suggests that the savings shown in this analysis of the audit period deliveries is more a function of averaging over a three year period than the specifics of purchase timing within the three year period. It should be remembered that the September 2003 acquisition date precluded UNS Gas from fully implementing the Price Stabilization Policy during the audit period.

Exhibit JEM-5 shows the cumulative NYMEX cost savings of the transition purchase timing strategies over the audit period. Both the UNS Gas 2005 Price Stabilization Policy and the UNS Gas 2006 Price Stabilization Policy scenarios would have saved around $2 million relative to the NYMEX costs of the actual fixed price gas purchases. The uniform transition scenario would have saved about $0.5 million relative to the NYMEX costs of the actual fixed price gas purchases. This analysis suggests that either UNS Gas' 2005 or 2006 Price Stabilization Policies would have saved money relative to the actual purchase timing over the part of the audit period that UNS Gas controlled purchase timing. It also would have saved money relative to a uniform purchase schedule over the part of the audit period that UNS Gas controlled purchase timing.

Q. Are you recommending that the Commission adjust the revenue recovery to disallow the excess NYMEX costs you calculated above?

A. No. The actual costs included in calculating the revenue requirement also add the basis to arrive at the receipt point prices and costs. To the extent that the basis is on average the same among the scenarios, the differential actual cost paid by UNS Gas would be equal to the differential NYMEX costs between scenarios. To the extent that the basis will differ for different scenarios, the savings may be more or less than what I calculated.

One of my purposes in developing the calculations was to evaluate and compare UNS Gas' 2005 Price Stabilization Policy to other scenarios to see whether the Policy is reasonable. I have concluded that the policy is a reasonable way to stabilize gas prices when utilizing low cost hedging instruments.

Another purpose of my analysis was to determine whether deviations in implementing the policies in the audit period would have had any material effect on the cost of gas in the audit period. I have determined that the alternate scenarios, including actual purchases, the 2005 Price Stabilization Policy and the "gold standard" of perfect dollar cost averaging (36 equal purchases over 36 months), all provide similar and relatively small levels of savings over the transition period. Thus I have concluded that deviations between the policy and the practice are not likely to have material effect on the cost of gas in the audit period.

COMMISSION APPROVAL OF UNS GAS' PRICE STABILIZATION POLICY

VI. The Commission should not approve UNS Gas' request to approve its 2006 Price Stabilization Policy.

Q. Does the 2006 Price Stabilization Policy as set forth in Mr. Hutchens' Exhibit DGH-1 correctly reflect UNS Gas' position?

A. No. There is a minor modification that was identified in response to Staff Data Request 2.15. The data request sought the analysis described in Section 2.2.2 of the 2006 Price Stabilization Policy that shows "that there are regular oscillations within price trends with a typical low point in the third week of each month." The response indicates that the "discussion portion of the policy ... does not accurately portray the final reasoning for setting the 20th of the month date in the policy" and that "UNS will make this correction in its next update of the policy." The incorrect language is contained in the document for which UNS Gas is seeking approval.

Q. Does the 2006 price stabilization policy have merit?

A. Yes. The 2006 Price Stabilization Policy, if implemented utilizing low cost hedging instruments, approximates a pure dollar cost averaging method for timing the purchases of natural gas to reduce gas price fluctuations. This method averages prices out over a multi-year time frame and dampens the effect of individual price extremes.

The 2006 Price Stabilization Policy provides purchasing discipline through its mechanistic approach and would ensure that some gas is purchased each trigger date. There are enough trigger dates to ensure that the average will not be dominated by a single extreme condition.

The 2006 Price Stabilization Policy also offers some flexibility to purchase additional discretionary fixed price gas when there are favorable market conditions. This flexibility allows UNS Gas to purchase discretionary volumes above 45% of the estimated monthly load as well as during hurricane season, which is blacked out for non-discretionary purchases.

Purchasing at least 45% and up to 80% of estimated monthly gas load on a fixed price basis insulates UNS Gas from price fluctuations. However, it may also lock UNS Gas in at higher than reasonable prices in the event that gas market prices fall after the purchase has been made. Thus, while it reduces the risk from price upswings, it increases the risk that gas price downswings will not benefit customers.

Q. Are there reasons that UNS Gas and the Commission should be wary of approving the 2006 Price Stabilization Policy?

A. Yes. The Price Stabilization Policy allows UNS Gas to use call options and collars as secondary mechanisms to stabilize prices, although these were not used during the audit period. Under the Price Stabilization Policy, UNS Gas could incur substantial costs for premiums (e.g., multi-year call options) and increase the cost of gas with no commensurate ratepayer benefit. The Commission's approval of the Price Stabilization Policy would give some presumption of prudence to a mechanism that would not be in the ratepayers interests.

While insulating against price increases, the fixed price forward physical contract mechanism that UNS Gas views as its primary hedging tool will also reduce the benefits of price decreases on the fixed price component of the gas supply. While it provides more protection from price swings by reducing volatility, it may result in higher cost than simply riding the market and buying gas at index. There is no way to know in advance whether the dollar cost averaging approach upon which the Price Stabilization Policy is based will result in higher or lower gas prices in any given period.

That suggests that UNS Gas must continually review its purchasing strategies and not put them on "autopilot." That is perhaps the greatest danger of Commission approval of the Price Stabilization Policy - it creates a "safe harbor" for UNS Gas to resist changing its procurement methods even if evolving market conditions make that change necessary. It can become less risky for UNS Gas to incur unnecessary gas costs that have a high probability of recovery because they followed an approved plan than to deviate from the plan even if it is warranted.

Q. Are you recommending that the Commission not grant UNS Gas' request to approve the Price Stabilization Policy?

A. Yes. This was the exact concern raised recently by the Public Utilities Commission of Nevada in its order in Docket No. 04-7004, dated November 18, 2004. The order is attached as Exhibit JEM-6. Sierra Pacific Power Company sought approval of its gas procurement plan, but did not explain how it would modify its procurement plan to reflect evolving market conditions. The Commission determined that it could not approve the plan and clearly held the utility accountable for monitoring the markets, identifying and responding to market changes by modifying its procurement plans. Paragraph 64 of the Public Utilities Commission of Nevada's order states:

> The Commission wishes to make it clear that the resource planning regulations are designed to allow SPPC the flexibility to make changes to its ESP if warranted - not to inoculate SPPC from regulatory risk. Accordingly, the Commission expects SPPC to formulate a clearly defined process for evaluating the effectiveness of its fuel procurement plan and risk management strategy (including its gas hedging strategy) and for changing these plans should conditions warrant.

UNS Gas has not provided any indication of how it would monitor and quickly respond to market conditions - especially if the utility had an approved plan creating the presumption of prudence. The Commission should not grant UNS Gas' request to approve the 2006 Price Stabilization Policy.

In the event that the Commission wishes to consider approving the 2006 Price Stabilization Policy, the Commission should require UNS Gas to provide a detailed explanation of how it will monitor the markets and respond to changes to the benefit of ratepayers. It should also require UNS Gas to show that any premiums for hedging instruments are reasonable and necessary to balance the objectives of stabilizing ratepayer prices and minimizing ratepayer costs. If the Commission approves the policy, it should condition the approval to be valid only as long as the conditions underlying the policy do not change. Changes in market conditions would invalidate the approval. That would help ensure that UNS Gas is held accountable for taking the necessary actions to analyze and prudently react to evolving gas market conditions.

Q. Does this conclude your testimony?

A. Yes it does.

JERRY E. MENDL
President
MSB Energy Associates

Areas of Expertise

+ Analysis of energy resource adequacy, cost and availability
+ Evaluation of alternative energy resource options
+ Analysis of electric utility bulk power supplies
+ Analysis of electric utility projected merger savings and implications on system operations and costs
+ Transmission system analysis
+ Service delivery and markets in a restructured electric utility industry

EDUCATION

1973 B.S. Degree in Nuclear Engineering, With Very High Honors, from the University of Wisconsin, Madison, Wisconsin

1974 M.S. Degree in Nuclear Engineering from the University of Wisconsin, Madison, Wisconsin.

EXPERIENCE

1987-Present
President
MSB Energy Associates, Inc.
Middleton, Wisconsin

Since co-founding MSB Energy Associates in 1988, Mendl has served public-sector clients in Kentucky, California, Utah, Nevada, Washington, Texas, Alaska, Iowa, Illinois, South Carolina, Connecticut, Massachusetts, Vermont, Maryland, Michigan, Missouri, Minnesota, Louisiana, Wisconsin, Pennsylvania, Georgia, Hawaii, Ohio, New Jersey, the District of Columbia and Ontario. Much of his recent work has involved electric utility restructuring, low-income consumer energy affordability and service issues, prudence of gas and electric utility planning and purchase practices, and analyzing need for transmission lines. He assesses "green pricing" tariffs for renewable electric resources and fuel/purchase power costs for electric and natural gas utility rate cases and renewable energy alternatives for utility construction cases. He evaluates electric utility restructuring alternatives and prepares restructuring policy recommendations and supporting technical information. He analyzes long-range plans and planning methods used by gas and electric utilities. He prepares and presents reports, recommendations and testimony.

He conducted engineering, environmental, economic and life-cycle cost analyses of alternate energy resource options, including improved end-use energy efficiency and renewable resources. Mendl developed state regulatory commission codes for implementing integrated resource planning and evaluated the adequacy of existing and proposed codes. Mendl was both organizer and presenter for a series of five least-cost planning workshops across the U.S. sponsored by the National Association of Regulatory Utility Commissioners (NARUC). He also participated in five Conservation Law Foundation collaborative projects in the northeastern states.

1974-1988

Administrator, Division of Systems Planning, Environmental Review and Consumer Analysis (1979-1988)
Director, Bureau of Environmental and Energy Systems (1976-1979)
Public Service Engineer (1974-1976)
State of Wisconsin, Public Service Commission
Madison, Wisconsin

Mendl was employed by the Wisconsin Public Service Commission for 14 years (1974-1988), and was responsible for the development and evolution of Wisconsin's long-range planning process for electric utilities. He had overall responsibility for directing the Commission's activities concerning utility long-range plans. In addition, Mendl had overall responsibility for and directed the preparation of environmental impact statements and environmental assessments, identifying expected impacts as well as evaluating alternatives, for five large power plants, numerous transmission lines, a major natural gas pipeline, and many policy issues including Electric Space Heat, Electric Utility Tariffs, Electric Sales Promotion, Small- Power Production and Cogeneration, and Extension of Service. Mendl was also responsible for directing the preparation of major studies, including *The Alternative Electric Power Supply Study, Alternative Electric Power Supply - Update*, and *Utility SO_2 Cleanup - Cost and Capability*. (The *Alternative Electric Power Supply Study* and *Update* identified renewable energy, load management and energy efficiency resources that would economically meet Wisconsin's long term electricity needs.) Mendl testified before the Wisconsin Commission in rate cases, planning cases, construction certificate cases and policy cases. He also appeared before other state Commissions and the Federal Energy Regulatory Commission.

OTHER DISTINCTIONS

Mendl staffed the NARUC Subcommittee on Energy Conservation for two and one-half years, and was closely involved with the preparation of the *Least-Cost Planning Handbook for Public Utility Commissioners*.

Mendl also was appointed to serve a four-year term on the Research Advisory Committee of the National Regulatory Research Institute (NRRI). One of seven regulatory staff selected nationally, Mendl helped NRRI to shape its research agenda to be more useful and responsive to the regulatory community.

Mendl is a Registered Professional Engineer in the State of Wisconsin.

Testimony

Mendl, since co-founding MSB Energy Associates in 1988, has testified in the following proceedings:

Submitted To:	Subject	Docket No.	Date
Nevada Public Utilities Commission	WESTPAC Utilities gas rates and deferred energy accounts	06-05016	2006
Nevada Public Utilities Commission	Nevada Power Integrated Resource Plan - gas purchase strategies	06-06051	2006
Nevada Public Utilities Commission	Sierra Pacific Power Energy Supply Plan - gas purchase strategies	06-07010	2006
Wisconsin Public Service Commission	Strategic Energy Assessment - electrical adequacy through 2012	5-ES-103	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (DEAA)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (DEAA)	05-12001	2006
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14717	2006
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14716	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER)	05-12001	2006
Nevada Public Utilities Commission	Nevada Power gas purchase practices – Energy Supply Plan	05-9017	2005
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices – Energy Supply Plan	05-9016	2005
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14403	2005

Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14401	2005
Kentucky Public Service Commission	Analysis of need for and electrical alternatives to EKPC Cranston-Rowan County transmission line	2005-00089	2005
Nevada Public Utilities Commission	Nevada Power gas purchase practices	04-9004	2004
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices	04-7004	2004
Nevada Public Utilities Commission	Prudence of Southwest Gas PGA costs, purchase practices	03-12012	2004
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-13902	2004
Wisconsin Public Service Commission	WPS rate case, low income programs, Weston 4 pre-certification expenses and capital	6690-UR-115	2003
Wisconsin Public Service Commission	Alliant rate case, RiverSide purchase power cost and incentive, Columbia maintenance and outages	6680-UR-113	2003
Wisconsin Public Service Commission	Alliant rate case, RockGen purchase power savings bonus, coal procurement	6680-UR-112	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in WPS rate case	6690-UR-114	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in MG&E rate case	3270-UR-111	2002
Wisconsin Public Service Commission	Assess renewable energy and other alternative resources in WE Power the Future –Port Washington case	05-CE-117	2002
Wisconsin Public Service Commission	Assess costs related to formation and operation of American Transmission Company	05-EI-129	2002
Wisconsin Public Service Commission	Filed comments in investigation of purchase power incentive mechanisms	05-EI-131	2002

Wisconsin Public Service Commission	Alliant rate case, adequacy of planning, purchase power contracts, coal contracts	6680-UR-111	2002
Michigan Public Service Commission	Analyze proposed gas cost recovery factor and plan, and gas procurement practices.	UR-13060	2002
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-113	2002
Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, purchase power contracts	6680-UR-110	2001
Wisconsin Public Service Commission	Wisconsin Electric fuel rate case, fuel costs, adequacy of planning, purchase power contracts	6630-UR-111	2001
Wisconsin Public Service Commission	Rulemaking regarding electric utility fuel and purchased power cost recovery	1-AC-197	2001
Wisconsin Public Service Commission	Nuclear spent fuel dry cask storage expansion at Point Beach	6630-CE-275	2000
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-112	2000
Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, prudence of plant maintenance practices, purchase power	6680-UR-110	2000
Wisconsin Public Service Commission	Rulemaking regarding environmental impact analysis and public input process	1-AC-185	1999
Michigan Public Service Commission	Over-recovery of revenues due to declining coal costs	U-11560	1999
Michigan Public Service Commission	Reasonableness of proposed settlement regarding recovery of nuclear plant replacement power costs through power cost recovery factor, suspension of factor	U-11181-R	1999
Michigan Public Service Commission	Fuel and purchase power surcharge, coal costs	U-11180-R	1998

Vermont Public Service Board	Prudence of Green Mountain Power purchase and management of Hydro-Quebec power	5983	1997
Michigan Public Service Commission	Analysis of coal costs, purchase practices, spot market	U-10971-R	1997
Michigan Public Service Commission	Suspension of the fuel and purchase power factor and planning in the transition to restructured utilities	U-11453	1997
Wisconsin Public Service Commission	IEC merger (of WPL/IES/IPC), need and environmental issues regarding proposed Mississippi River transmission crossings	6680-UM-100	1997
Pennsylvania Public Utility Commission	Restructuring, stranded cost, and securitization -- economic and environmental issues	R-00973877	1997
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of sales promotion	U-11181	1997
Wisconsin Public Service Commission	Primergy merger (of WEPCO/NSP), impact on state regulatory authority	6630-UM-100/4220-UM-101	1996
Michigan Public Service Commission	Gas cost recovery adjustments	U-10640-R	1996
Pennsylvania Public Utility Commission	Electric discounted rates, gas/electric competition	R-943280C0001	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of WEPCO/NSP merger	U-10966	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of energy efficiency	U-10971	1996
Minnesota House Committee on Taxes	Impact of cogeneration project on NSP ratepayers	HF637	1996
Minnesota Senate Committee on Jobs, Energy and Community Development	Impact of cogeneration project on NSP ratepayers	SF1147	1996

Wisconsin Public Service Commission	Role of DSM in Advance Plan-7 in light of potential restructuring	05-EP-7	1995
City Public Service Board of San Antonio	Integrated resource planning process (1992 EPAct hearings)	NA	1994
Maryland Public Service Commission	1992 EPAct rules	8630	1994
Georgia Public Service Commission	Commercial and Industrial DSM programs for Savannah Electric	4135-U	1993
Public Utilities Commission of Ohio	Analysis of forecasts and long range plans for Ohio Power and Columbus Southern (case settled)	90-659-EL-FOR and 90-660-EL-FOR	1990
Georgia Public Service Commission	Integrated resource plan analyses for Georgia Power and Savannah Electric	4131-U and 4134-U	1992
New Orleans City Council	Least-cost planning rules	14629 MCS	1991
District of Columbia Public Service Commission	Potomac Electric least-cost plan analysis	834 Phase II	1990
Massachusetts Department of Public Utilities	Boston Gas plan integrated resource plans	90-55	1990
Massachusetts Department of Public Utilities	Boston Gas commercial and industrial DSM, cost recovery	90-320	1991
Hawaii Public Service Commission	Least-cost resource planning	6617	1991
Georgia Public Service Commission	Least-cost planning and facility certification rules	4047-U	1991
New Jersey Board of Public Utilities Commissioners	Transmission line certificate (case settled)	NA	1990
South Carolina Public Service Commission	Transmission line certificate	88-519-E	1988
Vermont Public Service Board	Least-cost planning	5270	1988
D.C. Public Service Commission	Least-cost planning	834	1987

Mendl also assisted in preparing testimony and testified in numerous cases as a senior staff witness at the Wisconsin Public Service Commission. Dates are approximate.

- Advance Plans 1 through 4 (Dockets 05-EP-1 through 05-EP-4 -- on various occasions between 1977 and 1988) before the Wisconsin Public Service Commission
  A wide variety of planning issues including forecasts, nuclear vs coal power, alternative energy, renewable energy, load management, transmission planning, demand-side management resources, principles and methods of integrated resource planning

- Rate Cases (various occasions between 1976 and 1988) including landmark time-of-use rate case (6630-ER-2) for Wisconsin Electric Power
  Environmental and consumer impacts of rate levels and alternative rate designs before the Wisconsin Public Service Commission

- Construction Cases before the Wisconsin Public Service Commission
  Pleasant Prairie Power Plant (1976-1978)
  Germantown Combustion Turbines (1976-1977)
  Weston 3 (1979)
  Edgewater 5 (1980)
  Apple River -- Crystal Cave Transmission Line (1980)
  Prairie Island -- Eau Claire Transmission Line (1981-1982)
  North Madison -- Huiskamp -- Sycamore Transmission Line (1982)
  Point Beach Nuclear Plant Steam Generator Replacement (1982)
  Wisconsin Natural Gas Pipeline (1986)
  Need for power, appropriateness of the utility proposals, and the comparative economics of alternatives, environmental impacts

- Other Appearances while employed at the Wisconsin Public Service Commission
  Planning investigation before the Connecticut Department of Public Utilities Control Authority (1975); uranium availability and resource alternatives
  Rulemaking proceedings before Wisconsin Legislative Committees (1975-1982); planning, siting, and environmental impact analysis rules
  Tyrone Nuclear Project Termination cost recovery hearing before the Federal Energy Regulatory Commission (1980)
  Acid Rain legislation before Wisconsin Legislative Committees (1984-1985)

Selected Clients

Mendl has served the following public sector clients since 1988.

Client	Nature of Service
Alaska Housing Finance Corporation	Analysis of applicability of EPAct standards to Alaska resource selection process.

American Public Power Association	Prepared whitepaper on distributed resources, "Distributed Resources: Options for Public Power" and presented it to APPA National Meeting and distributed resources workshops.
California Low Income Governing Board	Analysis of options to deliver energy efficiency and assistance programs to low-income households in a restructured utility environment. Assist Board to develop low-income programs and policies under interim utility administration.
City of Chicago	Evaluate municipalization, especially regarding power availability and cost, transmission constraints, cogeneration potential.
Citizen's Utility Board of Wisconsin	Evaluate energy efficiency and load management programs in light of possible industry restructuring. Evaluate fuel rate cases and recommend revenue reductions in testimony for Alliant, Wisconsin Electric, Madison Gas & Electric and Wisconsin Public Service. Assess ATC formation and operation costs. Comment on and develop fuel rules, purchase power incentives.
Center for Neighborhood Technologies	Analysis of value of avoiding generation, transmission and distribution through energy efficiency, load management and distributed generation.
Conservation Law Foundation of New England	Collaboratives with Boston Edison, United Illuminating, Eastern Utilities Association, and Nantucket Electric regarding system planning approaches, avoided costs, resource screening. Collaborative with Green Mountain Power regarding Vermont Yankee end-of-life planning.
Dane County Energy Collaborative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet Dane County energy needs.
District of Columbia Energy Office	Analysis of DC Natural Gas' and PEPCo's integrated resource planning.
District of Columbia Public Service Commission	Testimony regarding least cost planning principles and rules.
Environmental Law and Policy Center	Analyzed potential impacts of proposed merger of Wisconsin Electric Power Company and Northern States Power Company on state regulatory authority in Wisconsin and Minnesota. Analyzed environmental impacts related to proposed merger of WPL and two Iowa utilities (IES and IPC), including the proposed transmission line crossings of

	Mississippi River and changes in air pollutant emissions.
Environmentalists/Penn. Energy Project	Analyzed PECO application to securitize stranded costs, especially on economic and environmental impacts that could result from authorizing overestimated stranded costs. Analyzed utility retail access pilot programs. Analyzed restructuring plans for PECO and PP&L.
Germantown Settlement, Philadelphia	Advise regarding business structure and market to aggregate load and/or provide energy efficiency and energy assistance services to low-income households.
Georgia Public Service Commission	Developed integrated resource planning and facility certification rules. Developed integrated resource plans and reviewed utility filings. Monitored utility DSM programs.
Hawaii Division of Consumer Advocacy	Developed integrated resource planning rules.
Iowa Department of Natural Resources	Developed and implemented workshops to train building operators and architects in energy efficiency and renewable energy resource opportunities.
Kentucky Public Service Commission	Analyzed need and alternatives for an EKPC transmission line and a prepared report. Presented testimony defending and explaining report.
Lake Michigan Coalition	Analyzed nuclear spent fuel dry cask storage expansion proposal
Maryland Public Service Commission	Reviewed two utility long-range plans and suggested improvements.
Massachusetts Division of Energy Resources	Analysis of Boston Gas Co. integrated resource plans and residential energy efficiency programs. Analysis of Boston Gas's commercial and industrial energy efficiency programs.
Michigan Community Action Agency Association	Analysis of Michigan electric utility restructuring proposals and impacts on retail prices. Analysis of MichCon gas cost recovery case and factor. Analyses of Indiana-Michigan, Consumers Energy, Wisconsin Electric and Northern States Power-Wisconsin power supply cost recovery cases and factors, including analysis of coal and power purchase practices, demand-side management, and nuclear plant outage costs. Analysis of Northern States Power/Wisconsin Electric Power Co. proposed merger.
Missouri Public Service Commission	Developed rules for electric resource planning and gas resource planning. Evaluated three electric utility plans filed pursuant to rules.

National Association of Regulatory Utility Commissioners	Organized, prepared and presented at five workshops throughout the U.S. sponsored by NARUC/DOE.
Natural Resources Defense Council, Mid-Atlantic Energy Project Collaborative	Evaluated resource planning and selection processes used by PSE&G to prepare plan filings.
New Jersey Department of the Public Advocate	Analyzed a transmission line application.
City of New Orleans	Developed least cost planning rules, guided a public working group to develop demand-side programs.
Nevada Office of Attorney General, Bureau of Consumer Protection	Sierra Pacific Power and Nevada Power Energy Supply Plans, Base Tariff Energy Rates and Deferred Energy Adjustment Accounts - gas purchase practices and prudence
Nevada Public Utilities Commission, Regulatory Operations Staff	Southwest Gas PGA prudence analysis, gas purchase practices
Northeast States for Coordinated Air Use Management	Electric vehicle analysis.
Ohio Office of Consumer Council	Analyzed two utilities' long-range plans and energy efficiency resource options.
Ontario Energy Board	Evaluated need for natural gas integrated resource planning rules.
The Opportunity Council	Evaluated gas DSM programs to be considered by Cascade Natural Gas in Washington.
Pennsylvania Office of Consumer Advocate	Evaluated demand-side management programs for several electric utilities. Investigated causes of Winter Emergency of 1994. Analyzed electric "flexible rates" and gas/electric competition issues. Analyzed electric reliability concerns in a restructured and competitive market.
RENEW Wisconsin	Analyzed MG&E's green pricing tariff, compared costs of conventional resources to green resources to determine whether a green premium tariff was appropriate
Responsible Use of Rural and Agricultural Land (RURAL)	Evaluated air and licensing issues related to a proposed power plant. Evaluated Public Service Commission proposed environmental and siting rule changes. Analyzed rules governing environmental review and public comment process and provided testimony before PSCW.

South Carolina Office of Consumer Advocate	Analyzed a transmission line application.
Southeast Wisconsin Energy Initiative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet energy needs in southeastern Wisconsin.
Texas ROSE	Developed electric planning rules. Analyzed city of San Antonio resource plan.
U.S. Environmental Protection Agency	Developed handbook, "Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act", which focuses on how energy efficiency and renewables relate to acid rain compliance strategies.
U.S. Environmental Protection Agency and U.S. Department of Energy	Analyzed and compared utility supply- and demand-side resource selection for Clean Air Act compliance on the Pennsylvania-New Jersey-Maryland (PJM) interconnection.
Utah Committee on Consumer Services	Analyzed DSM cost recovery mechanism, avoided cost methods, cost effectiveness tests, assisted in settlement discussions and would have prepared testimony if issues not settled.
Vermont Natural Resources Council and Vermont Public Interest Research Group	Testimony regarding least cost planning principles and rules.
Vermont Public Service Board	Testimony regarding the prudence of Green Mountain Power's planning and management of the Hydro-Quebec power purchase.
Wisconsin Department of Administration	Analysis of new home characteristics built in northeastern Wisconsin, permit data, survey development and report
Wisconsin's Environmental Decade	Review of Draft Environmental Impact Statement of major 345 kV transmission line in northwestern Wisconsin, develop comments.

Exhibit JEM-2 Redacted

Exhibit JEM-2 was in part based on confidential information provided by UNS Gas subject to a Protective Agreement. Exhibit JEM-2 is a 14 page exhibit, consisting of 28 graphs, one for each delivery month September 2003 through December 2005, inclusive. The graphs show the actual purchase dates and volumes plotted with a three-year NYMEX contract daily price history.

Exhibit JEM-3

NYMEX Cost for Fixed Price Gas UnderVarious Procurement Scenarios By Delivery Month

(Dollars)

	Sep.03	Oct.03	Nov.03	Dec.03
Actual Purchases	1,333,608	2,442,802	3,909,000	7,104,763
Three-Year Uniform	990,050	1,845,673	3,135,472	5,871,008
Three-Year UNS 2005 Policy	1,016,300	1,879,669	3,165,444	5,881,588
Transition Uniform	1,333,608	2,442,802	3,829,157	6,976,584
Transition UNS 2005 Policy	1,333,608	2,442,802	3,909,000	7,104,763
Transition UNS 2006 Policy	1,333,608	2,442,802	3,909,000	7,104,763

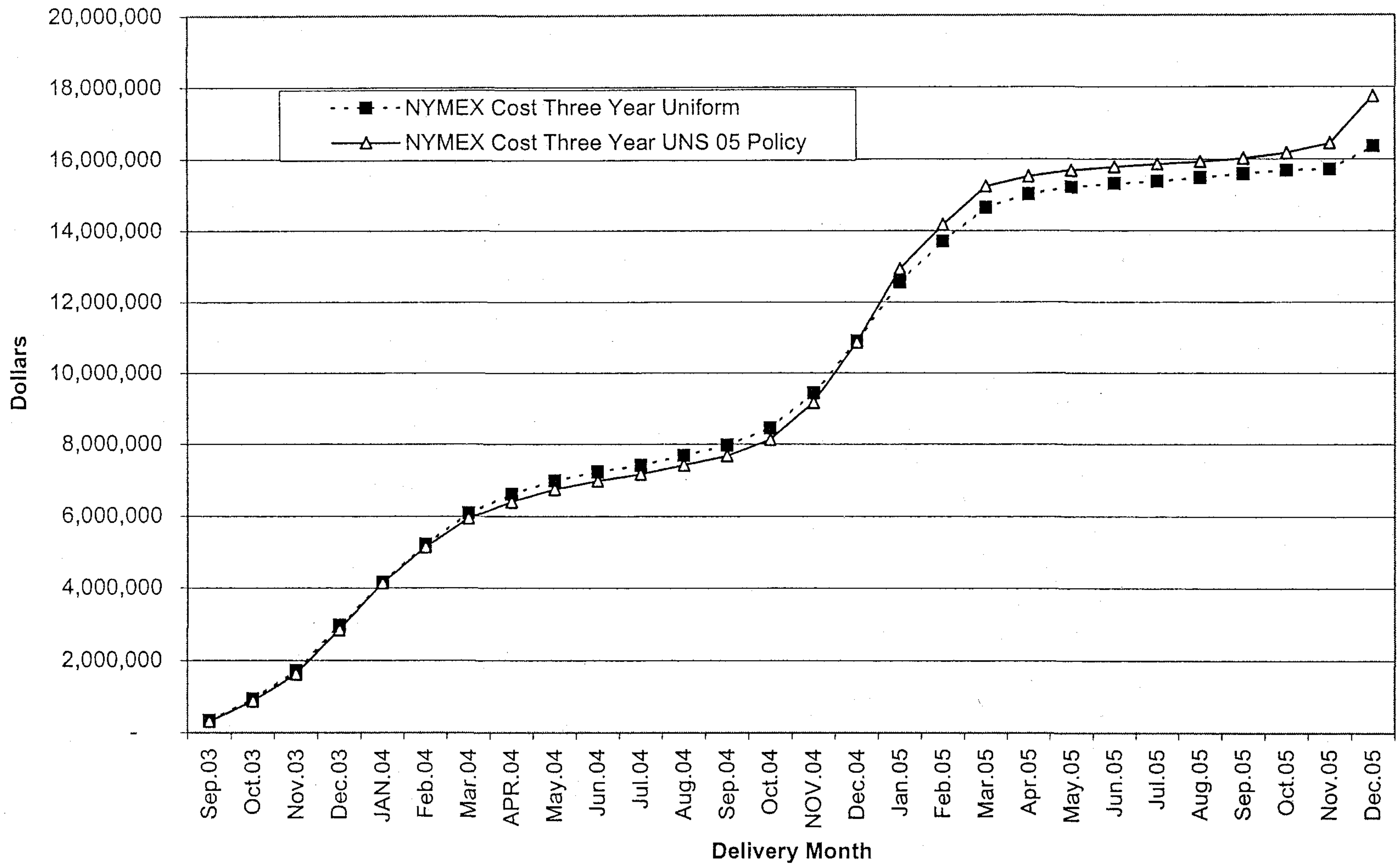
	Jan.04	Feb.04	Mar.04	Apr.04	May.04	Jun.04	Jul.04	Aug.04	Sep.04	Oct.04	NOV.04	Dec.04
Actual Purchases	7,354,415	6,240,580	5,277,595	2,414,196	1,604,959	1,095,638	853,968	1,144,631	1,154,449	2,039,864	4,249,501	7,422,585
Three-Year Uniform	6,151,165	5,181,900	4,403,526	1,891,648	1,228,953	850,246	676,123	861,934	874,448	1,569,495	3,254,189	5,964,273
Three-Year UNS 2005 Policy	6,061,850	5,247,526	4,469,610	1,963,201	1,259,669	856,605	669,423	891,364	894,949	1,588,429	3,212,946	5,726,955
Transition Uniform	7,438,341	6,427,420	5,412,934	2,293,558	1,492,463	1,039,330	820,494	1,075,246	1,078,130	1,902,415	3,945,294	7,242,681
Transition UNS 2005 Policy	7,354,415	6,240,580	5,277,595	2,420,653	1,563,959	1,064,854	827,531	1,096,947	1,102,281	1,956,542	3,959,907	7,057,719
Transition UNS 2006 Policy	7,354,415	6,240,580	5,277,595	2,311,027	1,500,083	1,038,586	828,042	1,098,258	1,110,989	1,968,141	3,950,852	7,003,380

	Jan.05	Feb.05	Mar.05	Apr.05	May.05	Jun.05	Jul.05	Aug.05	Sep.05	Oct.05	Nov.05	Dec.05
Actual Purchases	8,492,158	6,169,606	5,177,300	2,940,878	1,868,583	1,252,426	958,788	986,706	1,128,224	1,946,533	3,505,778	7,498,889
Three-Year Uniform	6,844,166	5,010,937	4,240,792	2,570,047	1,680,640	1,145,190	894,853	883,412	1,021,419	1,851,068	3,474,136	6,852,067
Three-Year UNS 2005 Policy	6,427,401	4,921,972	4,118,559	2,660,320	1,710,556	1,147,914	880,493	920,467	1,033,749	1,795,625	3,235,181	6,196,918
Transition Uniform	8,265,749	5,998,669	5,026,650	2,991,051	1,941,843	1,313,774	1,018,836	999,215	1,149,766	2,075,532	3,876,803	7,568,696
Transition UNS 2005 Policy	7,959,643	5,799,440	4,897,419	3,052,400	1,974,607	1,330,583	1,021,669	1,035,929	1,165,412	2,024,479	3,650,177	6,999,519
Transition UNS 2006 Policy	8,145,768	5,962,645	4,995,474	2,949,824	1,927,441	1,319,836	1,020,380	1,002,347	1,143,066	1,985,947	3,575,769	6,852,839

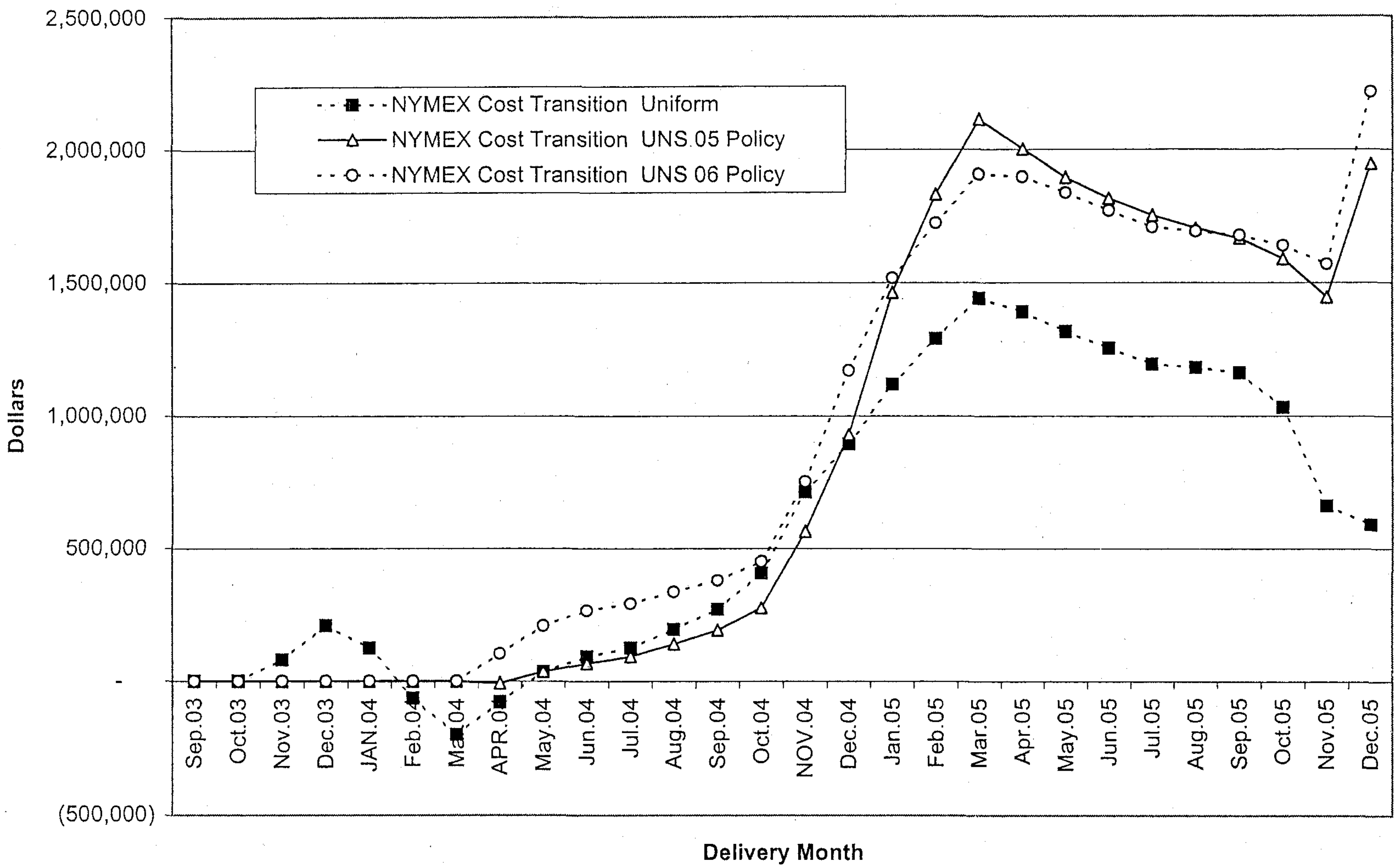
	TOTAL	Percent Difference
Actual Purchases	97,568,423	0.0%
Three-Year Uniform	81,218,829	-16.8%
Three-Year UNS 2005 Policy	79,834,687	-18.2%
Transition Uniform	96,977,040	-0.6%
Transition UNS 2005 Policy	95,624,432	-2.0%
Transition UNS 2006 Policy	95,353,458	-2.3%

Exhibit JEM-4

Cumulative NYMEX Cost Savings of Hypothetical Three-Year Purchase Timing Strategies Relative to NYMEX Costs of Actual Purchases For Gas Delivered September 2003 - December 2005



Cumulative NYMEX Cost Savings of Transition Purchase Timing Strategies
Relative to NYMEX Costs of Actual Purchases
For Gas Delivered September 2003 - December 2005



Re Sierra Pacific Power Company
Docket No. 04-7004

Nevada Public Utilities Commission
November 10, 2004

Before Soderberg, chairman, Chanos, and Linvill, commissioners And Jackson, commission secretary.

BY THE COMMISSION:

ORDER

*1 The Public Utilities Commission of Nevada ('Commission') makes the following findings of fact and conclusions of law:

I. Procedural History

1. On July 7, 2004, Sierra Pacific Power Company ('SPPC') filed an Application with the Public Utilities Commission of Nevada ('Commission'), designated as Docket No. 04-7004, for approval of its 2005-2024 Integrated Resource Plan.

2. The Application is filed pursuant to the Nevada Revised Statutes ('NRS') and the Nevada Administrative Code ('NAC'), Chapters 703 and 704, including but not limited to NRS 704.736 et seq. and NAC 704.9005 et seq. as modified by the regulations adopted in Legislative Counsel Bureau ('LCB') File No. R004- 04.

3. The Commission issued a public notice of the Application in accordance with state law and the Commission's Rules of Practice and Procedure.

4. On September 1, 2004, Petitions for Leave to Intervene were granted to: Alcoa, Inc. ('Alcoa'); Cantex, Inc. ('Cantex'); Cyanco Company ('Cyanco '); Eagle-Picher Minerals, Inc. ('EPMI'); Heavenly Valley, Limited Partnership ('Heavenly'); Lake Tahoe Horizon Casino Resort ('Horizon'); Kal-Kan Foods is Masterfoods USA, a division of Mars, Incorporated (' Kal-Kan'); Nevada Cement Company ('NVCC'); Premier Chemicals, LLC ('Premier'); R.R. Donnelley & Sons Company ('R.R. Donnelley'); The Ridge Tahoe Property Owners Association ('Ridge '); Royal Sierra Extrusions, Inc. ('Royal'); Washoe Medical Center, Inc. ('WMC,' collectively with Alcoa, Cantex, Cyanco, EPMI, Heavenly, Horizon, Kal-Kan, NVCC, Premier, R.R. Donnelley, Ridge, and Royal, 'Northern Nevada Industrial Electric Users,' 'NNIEU'); Newmont Mining Corporation ('Newmont '); and Barrick Goldstrike Mines Inc. ('Barrick'). The City of Fallon ('Fallon ') was granted limited intervention on transmission issues. The Washoe County Senior Law Project ('WSLP') was granted limited intervention on demand-side planning issues. The Renewable Energy Coalition of Nevada ('RECN') was granted limited intervention on long-term avoided cost ('LTAC') issues.

5. The Regulatory Operations Staff ('Staff') of the Commission and the Attorney General's Bureau of Consumer Protection ('BCP') participate as a matter of right.

6. On August 11, 2004, Newmont filed a Motion to Associate Counsel.

7. On August 25, 2004, a duly noticed prehearing conference was held in this matter.

8. On August 27, 2004, Barrick filed a Motion for Association of Local Counsel.

9. On September 1, 2004, a Procedural Order was issued in this matter adopting a procedural schedule for this docket and granting Newmont's Motion to Associate Counsel.

10. On September 8, 2004, RECN filed a Motion for Modification of Order on Petitions for Leave to Intervene ('Motion for Modification').

11. On September 9, 2004, Procedural Order No. 2 was issued in this matter granting Barrick's Motion for Association of Local Counsel.

12. On September 13, 2004, BCP filed a Response to RECN's Motion for Modification ('BCP's Response').

13. On September 14, 2004, Staff filed a Response to RECN's Motion for Modification ('Staff's Response').

14. On September 20, 2004, RECN filed a Reply to Staff's Response.

15. On October 4, 2004, Procedural Order No. 3 was issued in this matter denying RECN's Motion for Modification.

16. On October 7, 2004, SPPC and Staff filed Motions to Strike portions of the testimony filed by RECN Witness David Berry.

17. On October 8, 2004, Procedural Order No. 4 was issued in this matter shortening the time for responses to SPPC and Staff's Motions to Strike filed on October 7, 2004.

18. On October 11, 2004, NNIEU filed a Withdrawal of Petition for Leave to Intervene and Request for Commenter Status and Comments.

19. On October 12-13, 2004, a duly noticed hearing was held in this matter.

20. On October 12, 2004, Barrick requested to be excused from further participation in hearing as its concerns regarding the Application had been addressed. The Presiding Officer granted Barrick's request.

21. On October 12, 2004, a Stipulation, attached hereto as Attachment 1, was filed at the hearing. The Stipulation was signed by SPPC, BCP, Staff, Fallon, WSLP, Newmont, and

RECN.

22. On November 2, 2004, a Supplement to Stipulation ('Supplement'), attached hereto as Attachment 2, was filed. The Supplement was signed by SPPC, BCP, Staff, Fallon, WSLP, Newmont, and RECN.

II. Stipulation

*2 Summary of Stipulation

23. The Stipulation and the subsequent Supplement include recommendations that would settle all issues in this docket, except for the Energy Supply Plan ('ESP ') portion of the Action Plan.

24. Regarding the Demand Side Management ('DSM') issues, the parties recommended that SPPC's DSM Plan be approved with some minor modifications set forth in the Stipulation.

25. Regarding Supply-Side issues, the stipulating parties recommended several modifications. In particular, they recommended that SPPC should proceed with the permitting and development activities associated with the Tracy 500 MW combined cycle ('CC') project, but SPPC should file an amendment to its Resource Plan either reaffirming the need for the project, or proposing an alternative(s). Determination of the CC project as critical would be deferred until the need for the CC project is re-visited. Long-Term Avoided Cost issues would also be deferred to that proceeding. As a result, the total budget for the project from January 1, 2005, through August 1, 2005, would be reduced from $381,262,000 to $1,000,000.

26. Other items of note in the Stipulation include recommended approval of the Renewable Energy Promotion Program, the study of the feasibility of additional coal-fired generation at the Valmy generation site, the Power Plant Remaining Life Assessment Study, and the construction of the 345 kV transmission line from SPPC's East Tracy 345kV substation to a new substation ('Emma') located east of Virginia City. Regional Transmission Organization ('RTO') West (now called Grid West) expenditures were reduced from $5,900,000 to $950,000, which represents expenditures for 2005 only. The expenditures for 2006-2007 would be brought back to the Commission after a final determination as to SPPC's participation in RTO West (Grid West).

27. Overall, the recommendations proposed by the parties result in a reduction in the 2005-2009 total budget from $443,153,000 to $57,741,000, as detailed in the revised Action Plan Budget attached to the Supplement, previously attached hereto as Attachment 2.

Commission Discussion and Findings

28. The Commission finds that the recommendations made in the Stipulation and Supplement are in the public interest and should be approved.

III. Energy Supply Plan and Gas Hedging Strategy

SPPC's Positions

29. SPPC witnesses, Dr. John R. Ivey, Manager of Intermediate Term Resource Analysis, and Mr. Craig L. Berg, Manager of Market Analysis, sponsor sections of SPPC's ESP. (Exhibit 1, Volume II at Tab Berg, Ivey) SPPC is requesting Commission approval of its ESP for the period of 2005 through 2007, the action plan period. SPPC's ESP includes a recommendation for the issuance of a request for proposals for short-and intermediate-term purchased power contracts to fill a significant portion of SPPC's capacity requirements during that action plan period. SPPC is also requesting that the Commission approve its gas hedging strategy for April 2005 through March of 2006. Components of SPPC's gas hedging strategy include the procurement of physical gas requirements at indexed prices and the hedging of all the projected financial gas exposure using financially settled call options. (Hedges for the April 2005 through October 2005 season will be procured gradually from November 2004 through March 2005. Hedges for the November 2005 through March 2006 season will be procured gradually from June 2005 through October 2005.) SPPC also proposes to procure the call options at a strike price that is $0.50 'out-of-the-money' and purchase the options for each month and by hub based on the exposure at each hub during the month. (Exhibit 1, Volume II, Tab: Action Plan, at 3.)

30. In the Performance-Based Gas Methodology section of its ESP, SPPC also seeks approval to incorporate the natural gas purchased for resale for the gas distribution company in a proposal for a performance-based methodology for natural gas that it intends to submit via an amendment to its ESP. SPPC is also seeking other related approvals. (Exhibit 1, Volume III, page 52.)

Staff's Position

31. Staff's witness, Mr. Jon F. Davis, Electrical Engineer, provided testimony regarding SPPC's Energy Supply Plan ('ESP'). (Exhibit 5 at 2.) Mr. Davis identified a number of factors that could affect SPPC's open position. These factors include: a) customers leaving utility service under the provisions of NRS 704B; b) the loss of critical large generating supply for an extended period of time; c) advancing the construction schedule of the CC project; d) additional generation from customers' on-site resources or merchant activity; and e) abnormal weather.

32. Mr. Davis recommends that the Commission encourage SPPC to perform a regional nodal market analysis of the Pacific Northwest to better understand the challenges it faces in securing a reliable source of wholesale purchased power. He states that the analysis should study energy supply, energy pricing, and transmission supply limitations for the region assuming various hydroelectric production levels. (Id. at 13.) He believes the analysis will give SPPC a better understanding of the purchased power forward curves and the availability of purchased power on the open market. (Tr. at 158.) He adds that SPPC should use a regional model to develop forward curves that can be used to estimate the benefits of alternative strategies for varying levels of purchased power, transmission availability and power price volatility conditions. (Id. at 15; Tr. at 155.)

33. Mr. Davis states that SPPC's purchase power strategy appears reasonable. (Id. at 13.) He adds that SPPC should be mindful that two of its largest customers, Barrick and Newmont, may elect to purchase power from other providers and this could affect its purchase power strategy. (Id. at 14.)

34. Mr. Davis states that SPPC's concerns about price volatility of gas and generation capacity are valid and he believes SPPC's measures to counteract this volatility seem prudent. He adds that SPPC has developed a very conservative gas hedging strategy to address the market volatility. (Id. at 13.) He states that SPPC's 100% call option strategy allows SPPC to take advantage of any downward swings in gas prices and minimize its exposure to upward swings. He further states that SPPC should continually reevaluate its strategy to determine if conditions are such that a change in the strategy is warranted. He indicates that SPPC should take advantage of the stochastic capabilities of the Henwood RISKSYM software models to evaluate the risk-reward of the various option strategies. (Id. at 15.) He believes that once these models are in place, the Commission can be provided with information that will give it a better understanding of the various hedging strategies SPPC may be considering by illustrating the risks and rewards versus the cost of the various scenarios SPPC is considering. (Tr. at 161.)

35. Mr. Davis recommends that the Commission grant conditional approval of SPPC's ESP and hedging strategy subject to the following conditions: a) an appropriate response to factors that affect SPPC's open position; b) appropriate adjustments to its strategy should further analysis and evaluation of factors and conditions warrant an adjustment; c) performance by SPPC of a regional nodal analysis that develops forward curves for purchased power for low, normal, and high hydro years. He adds that should SPPC fail to implement its ESP or hedging strategy prudently, or alter them when warranted, it should be clear that adjustments might be appropriate in future deferred energy cases.

BCP's Position

36. BCP's Witness, Mr. George E. Wennerlyn, Select Energy Consulting, LLC, addresses the planned use of financial instruments as part of SPPC's natural gas acquisition program included in its ESP. (Exhibit 4 at 3.)

37. Mr. Wennerlyn states that the stated objectives in SPPC's ESP fall short of the intended goals of the current rèsource planning regulations as the ESP fails to balance the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan. He states that SPPC's 100% call option strategy completely ignores the goal of minimizing the cost of supply and places too much emphasis on minimizing the risk to ratepayers. He adds that SPPC's hedging strategy is too conservative and too costly for the potential benefits it is expected to achieve.(Id. at 4, 5.)

38. Mr. Wennerlyn states that his Attachment GEW-2, which provides a summary of SPPC's use of call options, supports his belief that SPPC's use of call options is less than desirable from a cost benefit analysis. (Id. at 5.)

39. Mr. Wennerlyn believes that there are better alternatives. He indicates that his comparison in Attachment GEW-3 of his proposed 'One-Third' strategy (one-third call option, one-third indexed, one-third fixed), to SPPC's 100 % call option strategy demonstrates that the 'One-Third' strategy results in lower gas costs. (Id. at 9.)

40. Mr. Wennerlyn recommends that the Commission not approve the SPPC's ESP. He believes SPPC should start with the 'One-Third' strategy. Then, SPPC personnel, Staff, and interested

parties would make necessary adjustments to reach a more balanced ESP.

41. BCP witness, Jerry E. Mendl, President of MSB Energy Associates, provides testimony addressing SPPC's planned procurement timetable for natural gas requirements. (Exhibit 3 at 2.)

42. Mr. Mendl states that SPPC's analysis of gas price risk mitigation options is flawed and that it does not support SPPC's conclusion that the 100% call option strategy is the preferred approach. He adds that SPPC's conclusion is subjective and believes that a less flawed analysis or a different interpretation of the results could result in the conclusion that the 100% call option strategy is not the preferred approach. (Id. at 3.)

43. Mr. Mendl believes that there are two main flaws with SPPC's risk mitigation analysis. The first is a bias built into SPPC's analysis by its Value at Risk ('VaR') calculation. He states that VaR does not measure the probability that prices will be lower than the average price of gas or the impact of those prices on total gas cost. He states that considering only VaR biases the analysis toward options that mitigate higher costs at the expense of options that increase the opportunity to reduce gas costs. Mr. Mendl provides Attachment JEM-2 which lists the Opportunity at Risk ('OaR'), the opportunity to reduce total gas costs below the average gas cost, for various gas procurement strategies. He concludes that there is substantial opportunity at risk for many of the mitigation strategies. He opines that the OaR must be considered when selecting a price risk mitigation strategy. He states that SPPC's strategy inappropriately fails to consider OaR. (Id. at 4.)

44. Mr. Mendl states that the second flaw with SPPC's risk mitigation analysis is with the modeling of fixed and indexed priced options. He states that SPPC assumed for the analysis that the fixed price products were purchased at the time the analysis was done. He believes this assumption is unrealistic for two reasons. First, commonly accepted strategies for purchasing fixed price products involve making purchases over time to diversify the supply cost as gas prices fluctuate. Second, SPPC's analysis does not take into consideration that portfolio costs can be reduced through securing supplies when prices are lower, or at least spreading purchases over time. (Id. at 6.)

45. Mr. Mendl believes that SPPC should consider other gas procurement strategies. He states that there are many other approaches that should be evaluated and considered and recommends that at least three aspects should be considered in developing additional approaches. These include: approaches that take a longer view of the gas markets to increase the likelihood that SPPC can take advantage of price valleys rather than being forced to buy gas during price peaks; approaches that better balance the cost and price volatility of gas supplies to mitigate both price volatility and total cost; and approaches that utilize increased amounts of fixed price contracts. (Id. at 8.)

46. Mr. Mendl adds that the manner of selecting fixed priced contracts can affect the outcome. He indicates that fixed price contracts can be procured through a bidding process where costs are kept down by competitive pressures, through dollar cost averaging or through a quartile index method or similar type method used to identify periods of low gas prices. (Id. at 8.)

47. With respect to determining when it is the best time to buy gas, he suggests the use of the quartile index method as proposed by MichCon. This method relies on historical data to help the utility determine when gas prices are at relatively low prices.

48. Mr. Mendl ultimately recommends that the Commission: a) not approve SPPC's proposed 100% call option strategy for purchasing gas; b) direct SPPC to meet with Staff and the parties to identify and evaluate gas procurement methods that place more emphasis on longer term (1-3 year) strategies, mitigate both price volatility and total cost, and make more use of fixed price products; c) direct SPPC to file a modified gas procurement proposal for Commission review within two months of the Commission order in this docket, reflecting, if possible, the consensus of the parties; and d) if the Commission approves a gas procurement strategy for SPPC, it should monitor its performance under other market conditions, and modify it as appropriate.

49. The BCP witnesses did not offer a position on SPPC's purchased power procurement plan or its non-gas fuel procurement plan.

SPPC's Rebuttal Position

50. SPPC's rebuttal witness, Dr. John Ivey, provides rebuttal testimony addressing criticisms made by BCP witnesses Mendl and Wennerlyn of SPPC's gas hedging plan, as well as addressing the recommendations made by Staff witness Davis. (Exhibit 6 at 1.) Dr. Ivey disagrees with the BCP's assertion that SPPC's analysis relies too heavily on VaR and that it is biased against options that increase the opportunity to reduce gas costs. He states that SPPC's gas hedging plan is not intended to beat the market price of natural gas or minimize the cost of natural gas supplies. He states that this does not mean that cost minimization is irrelevant in evaluating a hedging strategy. He adds that the magnitude of SPPC's price exposure, which is very large, affects the level of risk aversion that is included in its hedging strategy. (Id. at 2, 3.)

51. Dr. Ivey responds to Mr. Mendl's assertion that SPPC should consider other gas procurement strategies by stating that other hedging plans may be reasonable but that SPPC considered the full range of hedging portfolios before selecting a portfolio that he believes best serves SPPC's customers and their needs. (Id. at 6.)

52. Dr. Ivey responds to Mr. Wennerlyn's assertion that SPPC's call option strategy is less than desirable from a cost-benefit analysis by stating that the hedging plan should be judged based on whether it achieved its intended goal of reducing the standard deviation of the cost to serve. He believes SPPC's plan accomplishes this goal and that the expected benefits of SPPC's gas hedging program out-weigh the costs. He states that Mr. Wennerlyn did not offer any evidence supporting his claim that SPPC's call option strategy is too expensive other than stating that the cost of hedging in SPPC's hedging strategy was not recouped. Dr. Ivey concludes by stating that it is reasonable to incur the cost to hedge against rising gas prices given the potential cost of the exposure. (Id. at 6, 8, 9.)

53. Dr. Ivey believes that Mr. Mendl's concerns about how SPPC modeled the purchase of the fixed price products (SPPC's analysis reflects that they were all purchased at the same time) are unwarranted. He states that Mr. Mendl errs when he concludes that this simplifying assumption changes the analysis in any fundamental way. He states that this assumption does not skew the

results because the portfolios are all assumed to be hedged at the same time. He adds that SPPC's analysis models it this way but in actuality gas purchase and hedges are spread over time.

54. Dr. Ivey defends SPPC's proposed 100% call option strategy by stating that call options offer flexibility that fixed price products do not. He states that fixed priced products are not the answer because they are not attractive at current prices and preclude SPPC from taking advantage of lower prices for the benefit of its customers should they occur. (Id. at 8, 9.)

55. Dr. Ivey states that he is currently using RISKSYM in his analysis but that MARKETSYM is probably a more appropriate tool for doing the nodal analysis suggested by Staff witness, Mr. Davis. He adds that he is not currently using MARKETSYM and is not sure of SPPC's policy for use of this software. (Tr. at 194.)

56. Dr. Ivey states that if SPPC were already executing its gas procurement plan and saw a change in the market that it would repeat the analysis summarized in Figure ESP-31, Evaluation Criteria Applied to Gas Price Risk Mitigation Options, exercise some judgment and present this analysis to the Enterprise Risk Oversight Committee for approval. (Tr. at 186.)

57. Dr. Ivey states that he understands that just because SPPC has pre-approval for the fuel procurement plan he does not believe that Commission has granted it a blank check. He states that SPPC still has the burden of monitoring the market. (Tr. at 203.)

Commission Discussion and Findings

58. The Commission finds that the ESP should be approved subject to certain conditions as discussed below. A separate issue is whether the Commission is able to make a determination of prudence at this time with respect to the elements of the ESP. The three elements of the ESP, the power procurement plan, the fuel procurement plan, and the risk management strategy, are analyzed below as to whether each is being determined as prudent at this time pursuant to Section 26(3) of the new resource planning regulations.

59. With respect to the power procurement plan, Mr. Davis testified that SPPC's proposed purchased power strategy is reasonable and that he believes SPPC's measures to counteract purchased power volatility are prudent. No party submitted contrary evidence. The Commission acknowledges the uncertainty of load obligation mentioned in SPPC's ESP and Mr. Davis's testimony, and recognizes that the Stipulation submitted by the parties was based in part on this uncertainty. Given this uncertainty, the Commission expects SPPC to make the appropriate changes to its power procurement plan should the load obligation change. Therefore, the Commission finds that SPPC's power procurement plan, including the proposed plan to issue a Request for Proposals for short/intermediate-term purchase power contracts to fill a significant portion of its capacity requirements expected for 2005-2007, is prudent.

60. The Commission believes that Mr. Davis's recommendation that SPPC perform a regional nodal analysis has merit and finds that SPPC should complete this analysis. It is not clear from the record whether SPPC has the immediate capability to complete this analysis or, if not, when it will have the capability to do so. Given this uncertainty, the Commission finds that SPPC

should complete this analysis and include it in its next ESP update, scheduled for September 1, 2005.

61. The Commission has a number of concerns with SPPC's proposed fuel procurement plan and risk management strategy. The Commission is concerned that SPPC may be reluctant to change its fuel procurement plan and risk management strategy or consider other alternative strategies (e.g., a gas procurement strategy that takes a long-term view of the gas markets) once the Commission has found them to be prudent. SPPC's proposed 100% call option risk management strategy may do more to protect SPPC from regulatory risk than to protect consumers from commodity price volatility. The Commission is also concerned that SPPC's proposed 100% call option strategy may result in increased costs to ratepayers over and above an already high-cost commodity. Lastly, the Commission is concerned that SPPC's ESP does not include a formal process for measuring the effectiveness of the risk management strategy on a going forward basis, or for modifying it should conditions warrant.

62. Due to the concerns expressed above, the Commission cannot at this time make a finding that SPPC has demonstrated that its fuel procurement plan and risk management strategy balance the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan, as required by Section 26(3)(c) of the new resource planning regulations. Therefore, the Commission is withholding a determination of prudence with regard to the fuel procurement plan and risk management strategy.

63. Prudence with regard to the fuel procurement plan and risk management strategy will be determined in the appropriate deferred energy proceeding. SPPC must make reasonable decisions in implementing its fuel procurement plan and risk management strategy and if needed, deviating from them. SPPC will be held accountable for those decisions.

64. The Commission wishes to make it clear that the resource planning regulations are designed to allow SPPC the flexibility to make changes to its ESP if warranted -- not to inoculate SPPC from regulatory risk. Accordingly, the Commission expects SPPC to formulate a clearly defined process for evaluating the effectiveness of its fuel procurement plan and risk management strategy (including its gas hedging strategy) and for changing these plans should conditions warrant. The Commission also expects SPPC to keep Staff informed of any necessary deviations to the ESP and to make the required changes with or without resource planning pre-approval (as conditions warrant) in accordance with Section 29 of the new resource planning regulations and to fully document its reasoning for making the change(s) in accordance with the regulations.

65. The Commission does not believe that there was enough information filed by SPPC or the parties for the Commission to consider SPPC's requested approvals that are included in the Performance-Based Gas Methodology section of its ESP. Therefore, the Commission makes no determination on those requests. SPPC is free to re-file the requests with additional information in a future docket.

IV. Additional Compliance Items

66. SPPC, like Nevada Power Company, is heavily dependent upon fossil fuel generation, and has yet to meet its statutory renewable portfolio standard. Therefore, consistent with the compliance item required of Nevada Power Company in Docket Nos. 04-6029 and 04-6030, SPPC shall within six months of the issuance of this Order, file with the Commission an amendment to its 2005-2024 Integrated Resource Plan for the installation of solar or other appropriate renewable power generation technologies on company-owned buildings in Northern Nevada. The Commission may consider designation of such facilities as critical. This amendment shall be filed as a separate Application.

67. Furthermore, green power tariffs offer consumers the opportunity to opt for a richer mix of renewable resources while also allowing them to insulate themselves from the rate shock that comes from natural gas price volatility. Therefore, SPPC, as Nevada Power Company was required to in Docket Nos. 04- 6029 and 04-6030, should include in its next general rate case a green power tariff proposal that insulates consumers from fuel prices.

68. Also, as with the Order in Docket Nos. 04-6029 and 04-6030 relating to Nevada Power Company, the Commission is concerned with the reliance upon new generation to address peak load growth. Therefore, within six months of the issuance of this Order, SPPC shall file with the Commission an amendment to its 2005-2024 Integrated Resource Plan to provide incentives in order to encourage the installation of high-efficiency air conditioners and/or space heaters in new residential development and the retrofit of existing residences, as well as any other methods of residential conservation and/or efficiency SPPC may propose. This amendment shall be filed as a separate Application.

69. Further, the Commission believes that other options may be viable for fossil-fuel generation and should be explored. Therefore, within twenty-four months of the issuance of this Order, SPPC shall investigate and file a report with the Commission on integrated coal gasification technology and the potential for the use of this technology as either modifications to existing company-owned generation facilities, including the Pi +-on Pine Project, or new company-owned generation facilities.

*3 THEREFORE, based upon the foregoing findings and conclusions, it is hereby ORDERED that:

1. The Action Plan of Sierra Pacific Power Company, with the exception of the Energy Supply Plan, is APPROVED as recommended in the Stipulation and Supplement to Stipulation, attached hereto and incorporated herein as Attachments 1 and 2 respectively.

2. The Energy Supply Plan portion of Sierra Pacific Power Company's Action Plan is APPROVED. The power procurement portion of the Energy Supply Plan is found prudent; however, no determination of prudency is made with regard to the fuel procurement plan and risk management strategy, as detailed in paragraphs 58-65 above.

3. Within six months of the issuance of this Order, Sierra Pacific Power Company SHALL FILE with the Commission an amendment to its 2005-2024 Integrated Resource Plan for the installation of solar or other appropriate renewable power generation technologies on company-owned buildings in Northern Nevada. This amendment shall be filed as a separate Application.

4. Sierra Pacific Power Company SHALL FILE with its next General Rate Case a green power tariff that offers consumers the option of purchasing a richer mix of renewable energy and insulates them from fuel prices.

5. Within six months of the issuance of this Order, Sierra Pacific Power Company SHALL FILE with the Commission an amendment to its 2005-2024 Integrated Resource Plan to provide incentives in order to encourage the installation of high-efficiency air conditioners and/or space heaters in new residential development and the retrofit of existing residences, as well as any other methods of residential conservation and/or efficiency Sierra Pacific Power Company may propose. This amendment shall be filed as a separate Application.

6. Within twenty-four months of the issuance of this Order, SPPC SHALL INVESTIGATE AND FILE A REPORT with the Commission on integrated coal gasification technology and the potential for the use of this technology for either modifications to existing company-owned generation facilities, including the Pinon Pine Project, or new company-owned generation facilities.

7. The Commission retains jurisdiction for the purpose of correcting any errors that may have occurred in the drafting or issuance of this Order.

8. Except as specifically set forth herein, acceptance of the Stipulation and Supplement to Stipulation's agreement does not constitute approval of, or precedent regarding, any legal or factual issue in this proceeding.

9. All arguments of the parties raised in these proceedings, including but not limited to arguments raised in the hearing, not expressly discussed herein have been considered and either rejected or found to be non-essential further support for this Order.

Dated: Carson City, Nevada

EXHIBIT

ALL-STATE LEGAL®

S-22

admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

SURREBUTTAL

TESTIMONY

OF

JERRY E. MENDL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

APRIL 4, 2007

Q. Please state your name and business address.

A. My name is Jerry E. Mendl. I am the President of MSB Energy Associates, Inc. ("MSB"). My business address is MSB Energy Associates, Inc., 7507 Hubbard Avenue, Middleton, Wisconsin 53562.

Q. Are you the same Jerry E. Mendl that filed Direct Testimony in this case?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my testimony is to provide a response to the Rebuttal Testimony filed by UNS Gas, Inc. ("UNS Gas"), and specifically Mr. James Pignatelli and Mr. David Hutchens. I disagree with their request that the Commission approve UNS Gas' Price Stabilization Policy.

Q. In his Rebuttal Testimony, Mr. Hutchens said that your concern that UNS Gas' price Stabilization Policy would allow the Company to use "options and collars which could add to the cost without commensurate benefit to the ratepayers" is unfounded. What is your reaction?

A. The fact that UNS Gas has never used call options and collars does not obviate the fact that the Stabilization Policy for which UNS Gas sought approval explicitly allows the Company to use them. If the Commission were to approve the Stabilization Policy, and the Company elected to use a hedging mechanism that added to the cost without commensurate benefit to the ratepayers, the Company would nonetheless be acting in accordance with the Commission-approved policy. Even if it could be shown that the Company's use of the costly hedging mechanism was imprudent, it would dramatically change the burden of proof, and insulate the Company, because its use was consistent with an approved policy. The Commission should not approve a Stabilization Policy that provides the Company with the flexibility to take imprudent actions while limiting the ability of the Commission and interveners to hold the Company accountable.

Q. Mr. Hutchens offered that the Company would remove from its Stabilization Policy options that could incur substantial costs/premiums. Is that a solution to your concerns about approving the Stabilization Policy?

A. No. My concern is maintaining accountability while maintaining flexibility to respond to volatile and changing markets. Removing call options and collars that add to the cost without commensurate benefit to the ratepayers from the Stabilization Policy would be good. However, as I indicated in my Direct Testimony, there may be circumstances under which collars and call options may provide benefit to ratepayers commensurate with the cost. Removing these categorically would not be reasonable.

Mr. Hutchens indicated that the Company includes these secondary hedging mechanisms in its Stabilization Policy to maintain flexibility. I do not take issue with the Company maintaining flexibility. Maintaining flexibility is another way of saying that the Company retains the prerogative to take appropriate action. When the Company retains flexibility and management prerogative, it must be held accountable for its exercise of that prerogative. The Company's initial request for approval of the Stabilization Policy retains the Company's management prerogative but reduces its accountability. Thus I did not recommend that the Commission approve the Stabilization Policy.

Mr, Hutchens' offer to limit the Company's prerogative by removing call options and collars from hedging mechanisms allowable under the Stabilization Policy would clearly avoid circumstances where those mechanisms increase the cost without commensurate ratepayer benefits. However, the categorical exclusion of call options and collars also eliminates strategies that may in some circumstances be appropriate. Approval of a Stabilization Policy that categorically excludes hedging mechanisms (including those that could be potentially useful under some circumstances) does not hold the Company accountable for pursuing those mechanisms when they are in the ratepayers' interests. Thus I cannot support Mr. Hutchens' proposal to approve the Stabilization Policy as modified to exclude call options and collars.

Q. What is the solution to your concern about approving the Stabilization Policy?

A. My solution is to not approve the Stabilization Policy, either including or excluding the call option and collar hedging mechanisms, because doing so decreases the accountability of UNS Gas for its actions.

There is no disagreement that gas markets and prices have been volatile, and that they are likely to continue to be volatile. The Stabilization Policy is a reasonable internal mechanism for UNS Gas to employ to monitor and control the impacts of gas price volatility as long as it is continuously updated and adjusted for changing market conditions. It would not be reasonable for UNS Gas to combat the impacts of a dynamic market using a static approach.

The disagreement arises when UNS Gas seeks Commission approval of the Stabilization Policy. Commission approval fixes the Stabilization Policy until the Commission approves a revised policy. The Company intends to annually update the Stabilization Policy, meaning that a Commission approval would be static for at least a year, much longer than appropriate in the dynamic market. In a volatile market, the utility must be held accountable for reacting as quickly as possible to changing conditions. Approval of the Stabilization Policy as UNS Gas proposed actually creates a harmful safe harbor in which UNS Gas is less likely to react quickly to changing market conditions because it faces greater risk in deviating from a Commission-approved policy, even if deviating would better serve ratepayer interests.

Q. Mr. Hutchens testifies that your concern that the approval of the Stabilization Policy would put the Company on autopilot is inconsistent with the Company's behavior and the policy itself. Do you agree?

A. No. My point is that if the Commission approves the Stabilization Policy, actions consistent with the approved policy *will be given a presumption of prudence*. That is clearly the Company's intention in pursuing the approval of the Stabilization Policy, confirmed in Mr. Hutchens' testimony that "it would not be acceptable for the Company to implement a procurement policy that could later be second-guessed." (Rebuttal page 11, lines 23-25)

Once approved, the policy has a presumption of prudence. The Company perceives more risk by deviating from the approved policy than by staying with the policy longer than it should in light of changed conditions. Approving the proposed Stabilization Policy does not protect the ratepayers, and in fact harms them if the Company reacts more slowly to changing market conditions. However, approving the proposed Stabilization Policy would insulate UNS Gas from cost recovery risks associated with gas procurement.

Q. Is your concern inconsistent with the Company's behavior and the policy itself as Mr. Hutchens alleges?

A. No. The annual reviews and updates about which Mr. Hutchens testified are too infrequent in volatile markets. Mr. Hutchens indicates, as does the Stabilization Policy

(Risk Management Committee meets quarterly), that reviews occur more frequently. However, the Company reviews do not change the Commission-approved policy - that takes a Commission action. Until the approved policy is changed, the Company has strong incentive to act in accordance with the Commission-approved policy. Thus, Company reviews, even if they take place quarterly or more frequently, do not equate to changes in Company actions or to changes in the Commission-approved policy.

Mr. Hutchens does not take his argument for a Commission approval of the Stabilization Policy far enough. Namely, if there was a Commission-approved policy, how would the Commission approval process be updated frequently enough to respond to the volatile natural gas markets and other changing conditions?

Q. Are you suggesting that the Commission should engage in these quarterly or more frequent stabilization policy reviews and updates?

A. No. I think that would be burdensome and procedurally unworkable. Since each updated approval would constitute a new presumption of prudence that could affect the future rights of the interveners, these updating processes should involve interveners and a record, and as a result would be cumbersome. My recommendation is that the Commission not approve the Stabilization Policy.

If the Commission chooses to approve a Stabilization Policy, my recommendation is that it should condition the approval to be valid only as long as the conditions underlying the policy do not change. That provides guidance to UNS Gas, but recognizes that conditions may change and holds UNS Gas accountable for responding promptly to those changes.

Q. Do you agree with Mr. Hutchens' Rebuttal Testimony on page 11, line 23, that "it would not be acceptable for the Company to implement a procurement policy that could later be second-guessed?"

A. No. From the Commission and ratepayer perspectives, it is appropriate that UNS Gas be held accountable for its gas purchases. It is not appropriate for UNS Gas to create a procurement policy that precludes interveners and the Commission from questioning whether UNS Gas was reasonably procuring gas in light of changing conditions.

Q. Does the new UNS Gas, Inc. Price Stabilization Policy effective January 1, 2007, attached to Mr. Hutchens' Rebuttal Testimony as Exhibit DGH-4, reflect his offer to remove from its Stabilization Policy options that could incur substantial costs/premiums?

A. No. The new Price Stabilization Policy is the same as the Price Stabilization Policy UNS Gas adopted effective January 1, 2005 and 2006, in that all three policies include the use of call options and collars as secondary methods to achieve price stabilization.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST ND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-060463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

DIRECT

TESTIMONY

OF

STEVEN W. RUBACK

ON BEHALF OF

ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

FEBRUARY 23, 2007

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SCHEDULES

EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My testimony addresses the Company's proposed rate design and Throughput Adjustment Mechanism.

My findings and recommendations for each of these areas are as follows:

1) UNS proposed rate design proposes to recover more of its costs from higher fixed charges. I recommend that the rates proposed by UNS' be rejected. Another Staff witness, Ralph C. Smith, is presenting Staff's proposed rate design.

2) The Commission should reject the proposed Throughput Adjustment Mechanism ("TAM"), because it is inequitable to ratepayers. The TAM shifts the risk of declining usage attributable to weather, economics and conservation from UNS Gas to ratepayers. There is precedent for rejection of a Rate Decoupling Mechanism such as TAM. I also recommend that the Commission reject the implementation of the TAM because it is piecemeal ratemaking.

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Steven W. Ruback, and my business address is 785 Washington Street, Canton, Massachusetts 02021.

Q. WHAT IS YOUR OCCUPATION?

A. I am the founder and a principal of The Columbia Group, Inc., which is a public interest consulting firm specializing in public utility issues on behalf of state agencies, local governments, municipal utilities, offices of attorneys general and the staff of public utility commissions. My practice consists of providing gas and electric expert testimony, technical support for utility negotiations, municipal utility rate studies and other related rate services.

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I am a lawyer and engineer. For more than 25 years I have worked as a rate consultant on behalf of the public interest. My principal areas of concentration have been the gas and electric utility industries. I have filed expert testimonies in natural gas cases for more than 25 years. I have undertaken more than 400 utility assignments, and I have provided expert testimony in over 200 proceedings.

My principal areas of concentration are: (1) cost allocation studies (2) class revenue requirements (3) rate design (4) unbundling (5) transportation issues (6) competition (7) restructuring (8) design day forecasting (9) gas supply (10) PGA and procurement issues (11) hedging and (12) related policy issues.

Since our founding in April of 1981, we have worked solely on behalf of the public and ratepayer interests. Representative clients include, but are not limited to, the Consumers' Utility Counsel Division of Georgia, the Connecticut Office of Consumer Counsel, the Vermont Public Service Commission, the Virginia Association of Municipalities and the Virginia Association of Counties.

I was New Hampshire's first Consumer Advocate for the Legislative Utility Consumers' Counsel in 1976. I graduated from Clarkson College of Technology in 1968 with a degree in Interdisciplinary Engineering & Management. I graduated from the State University of New York at Buffalo, School of Law, in 1973. I have not, however, practiced law since 1976, and my current practice consists solely of providing utility consulting services.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I was asked by the Staff of the Arizona Corporation Commission ("Commission") to review the rate design aspects of UNS Gas, Inc. ("UNS" or the "Company") application for a general change or modification in its rates, charges and tariffs, and to comment upon the Company's proposals, report my findings and, if appropriate, make recommendations for the Commission's consideration.

Q. HOW IS TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows: Section I is an Executive Summary which summarizes my findings, recommendations and lists my testimony exhibits. Section II provides my qualifications and experience and the purpose of my testimony. Section III addresses Rate Design. Section IV addresses Decoupling.

Q. PLEASE LIST YOUR EXHIBITS THAT SUPPORT THIS TESTIMONY.

A. STF-SWR-1 Front End Load Analysis

STF-SWR-2 Calculation of Customer Charge

STF-SWR-3 Resolution on Gas and Electric Energy Efficiency

RATE DESIGN

Q. WOULD YOU PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S RATE DESIGN PROPOSALS?

A. The principal rate design proposals are the overwhelming increases in fixed customer charges, the corresponding reduction in volumetric charges and seasonal customer charges for the Residential class.

The Company is proposing a staggering increase in the fixed customer charges for all classes of service. The most extreme customer charge proposal is the Company's request to increase the Residential customer charge by more than 185 percent, during the summer period and 57 percent in the winter period. The remaining classes would also experience sharp customer charge increases.

Rate design is a zero sum exercise. Because the allowed revenue requirement is fixed, increases in customer charges must be offset, in this case, by a corresponding reduction in volumetric rates. Based on my experience, utilities are eager to increase fixed charges to reduce the risk of under recovery of the distribution revenue requirement. UNS' proposal is extreme because the proposed customer charges are intended to recover all of the proposed increase plus some of the margin recovered in existing volumetric rates.

Q. PLEASE COMPARE THE COMPANY'S PRESENT AND PROPOSED CUSTOMER CHARGES?

A. The specifics of the Company's proposal are as follows:

TABLE 1: CUSTOMER CHARGE AT PRESENT AND PROPOSED RATES

Class of Service	Present Rates	Proposed Rates	% Increase
RES (R-10) Cust Charge (Sum: Apr - Nov)	7.00	20.00	185.71%
RES (R-10) Cust.Charge (Win: Dec-Mar)	7.00	11.00	57.14%
RES (R-12) Cust Charge (Sum: Apr - Nov)	7.00	20.00	185.71%
RES (R-12) Cust Charge (Win: Dec-Mar)	7.00	11.00	57.14%
SM CS (C-20) Customer Charge	11.00	20.00	81.82%
LG CS (C-22) and CT Customer Charge	85.00	120.00	41.18%
SM IS (I-30) Customer Charge	11.00	20.00	81.82%
LG IS (I-32) and IT Customer Charge	85.00	120.00	41.18%
SM PA (PA-40) Customer Charge	11.00	20.00	81.82%
LG PA (PA-42) and PAT Customer Charge	85.00	120.00	41.18%
Special Gas Light Cust. Charge Lighting Group A	13.57	16.47	21.36%
Special Gas Light Cust. Customer Charge Lighting Group B	16.28	19.70	21.02%
Irrigation (IR-60) Customer Charge	11.00	20.00	81.82%

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE RESIDENTIAL CUSTOMER CHARGE FROM $ 7.00 TO $20.00 IN THE SUMMER MONTHS AND $11.00 IN THE WINTER MONTHS JUSTIFIED?

A. No. There are several problems with the Company's customer charge proposal. The Company's proposal presents a serious front end loading problem, a decoupling issue and gradualism problem.

Q. HAVE YOU CALCULATED THE COMPOSITE RESIDENTIAL CUSTOMER CHARGE?

A. Yes. The composite residential charge is $17.00 a month; this is a 143 percent increase to the existing Residential charge of $7.00 a month. The Commission should not accept the Company's proposals to increase the customer charges as UNS requested, or to create a seasonal customer charge. An increase to $17.00 for Residential customers violates the basic rate design criterion of gradualism. The seasonal customer charges are also not appropriate because the customer costs included in a customer charge do not change by season.

Q. PLEASE DISCUSS THE FRONT END LOADING PROBLEM PRESENTED BY THE COMPANY'S PROPOSED CUSTOMER CHARGES.

A. The Company's proposal to increase the customer charges, specifically in the smaller classes by 81 percent to over 185 percent, is a classic example of front-end loading. These proposed increases would allow the Company to recover a disproportionate amount of revenue through the customer charge.

Q. WHAT ARE THE RESULTS OF THE ALLOCATION OF CUSTOMER CHARGES TO THE OTHER CLASSES OF SERVICE?

A. As shown in Exhibit STF-SWR-1, the recovery of the Company's proposed revenue increase for each class varies in the amount that is recovered through the increase to the class's customer charge. As stated above, the Residential class recovers more than twice the proposed revenue increase from the increase in its customer charge, the Small Commercial Service (C20) class will recover 66 percent of the Company's proposed increase, Small Public Authority Class (PA-40) will recover almost 36 percent, and the remaining classes range from 17 percent to 2 percent.

The Company is proposing to recover more than its requested revenue increase for the Residential class in its newly proposed customer charge. The Company is proposing to collect an increase of $14.6 million in the Residential (R-10) rate class under its proposed customer charges, but they are only requesting a total increase of $6.58 million for the Residential Class (See Exhibit STF-SWR-1). Increasing the customer charges to provide more revenue than the proposed revenue increase requires that existing volumetric rates be reduced, which further decreases the Company's risk.

Q. WERE YOU SURPRISED BY THE COMPANY'S PROPOSED CUSTOMER CHARGE INCREASE?

A. I was not surprised that UNS proposed to increase fixed customer charges. I was, however, surprised by the size of the proposed increase and that more than the proposed revenue increase was to be recovered by fixed charge increases.

During recent years many utilities, such as UNS, have proposed fixed charge increases to reduce their risk of under-recovery of fixed distribution costs. The reason for this proposal is to increase fixed cost recovery for the utility's overall revenue requirement, regardless of how much or little gas is actually used by customers. This rate design strategy is common among utilities throughout the country. The goal is simply to collect more revenue from fixed charges, independent of usage.

There is, however, an important distinction between the Company's customer charge and others that I have reviewed. The distinction is that utilities propose increases in fixed charges to recover a disproportionate amount of the proposed revenue increase, but UNS has proposed to recover all of the proposed increase and some of the volumetric margin recovered in existing rates.

Q. HAVE YOU CALCULATED 100 PERCENT FULLY ALLOCATED CUSTOMER COSTS?

A. Yes, I have calculated 100 percent fully allocated customer costs. The calculations are provided on my Exhibit STF-SWR-2.

A customer charge should only include direct customer costs such as meter reading, customer accounting, meter and house regulators, and customer installations. Costs such as general plant and administrative and general costs should not be included.

In order to calculate the customer-related capital costs, I used a carrying charge approach. A carrying charge approach is used by utilities to estimate the annual revenue requirement required by a dollar of new plant. I used a carrying charge of 18 percent, which represents an estimate of return, depreciation and federal, state and local taxes.

Q. IS THERE ANY REGULATORY REQUIREMENT THAT THE CUSTOMER CHARGE SHOULD RECOVER 100 PERCENT OF ALLOCATED CUSTOMER COSTS?

A. No. Customer charges rarely, if ever, are set to cover their allocated customer costs. This is a long standing regulatory practice. Pricing the customer charge below allocated customer costs is intended to promote public acceptability, which is a valid rate design goal.

Q. IS THERE A RATE DESIGN REQUIREMENT THAT CUSTOMER CHARGES SHOULD RECOVER 100 PERCENT OF ALLOCATED CUSTOMER COSTS?

A. There is simply no ratemaking requirement that customer charges or other fixed charges recover a specific level of costs. Regulatory commissions throughout the country routinely set customer charges and demand charges below the costs determined in a cost of service study. For small customers, the setting of the customer charge is one of the most controversial aspects of rate design. Based on my experience, commissions have a longstanding practice of pricing customer charges below the customer costs. The primary reason for this is public acceptability, which is a valid rate design criterion, and the impact on small customers.

Q. IF CUSTOMER CHARGES ARE REDUCED FROM THE COMPANY'S PROPOSAL, WILL RATES BE DESIGNED TO RECOVER THE CLASS REVENUE REQUIREMENTS?

A. Lower customer charges than proposed by the Company do not mean that rates will not be designed to recover class revenue requirements. Volumetric charges would be increased from the charges proposed to produce the same class revenue requirements.

Q. DO CUSTOMER CHARGES IMPEDE THE ABILITY OF CUSTOMERS TO CONTROL THEIR BILL?

A. Customer charges are inelastic. Inelasticity is an inappropriate concept to build into a tariff design. Unlike commodity charges, which provide customers the opportunity to control their bills by changing the amount of gas used or peak demand imposed on the system, a customer charge does not change with reduced consumption or less demand. The only way a customer can avoid customer charges is to discontinue all gas service.

Q. IS A CUSTOMER CHARGE A TYPE OF DECOUPLING MECHANISM?

A. Yes. A customer charge is an example of a decoupling mechanism. A customer charge breaks the link between revenue and throughput because the customer charge remains the same regardless of throughput.

Q. ARE THE PROPOSED REDUCTIONS IN VOLUMETRIC RATES A STEP TOWARD A STRAIGHT-FIXED-VARIABLE RATE DESIGN?

A. UNS' rate design proposal is a step towards a Straight Fixed Variable ("SFV") rate design. UNS proposes to recover an enormous amount of its overall revenue requirement from *fixed* customer charges, not volumetric charges.

One of the basic tenets of public utility regulation is that a utility be provided with the <u>opportunity</u> to earn a reasonable rate of return, not a guarantee. A guaranteed recovery of the distribution revenue requirement involves no risk to the Company and if allowed, requires a minimal return on equity. UNS' rate design proposal, which is a healthy step towards a SFV rate design, violates the well-established and long-standing regulatory principle that a utility should have a reasonable opportunity, not a guarantee to earn its allowed rate of return.

Q. IS FERC'S IMPLEMENTATION OF THE SFV RATE DESIGN PRECEDENT FOR UNS' PROPOSAL TO INCREASE FIXED CHARGES AND DECREASE VOLUMETRIC CHARGES?

A. The SFV pipeline rate design is not appropriate for retail distribution rate design because the theoretical underpinning of the SFV pipeline rate design does not apply to distribution service. FERC's SFV was implemented <u>to ration pipeline design day capacity by price</u>. The SFV method should not be applicable to distribution service because there is no need to ration retail distribution capacity. There is no need to ration UNS' distribution capacity since UNS has no distribution constraints and has not had to curtail distribution service over the last 5 years.

In 1998, the State Corporation Commission of the State of Kansas rejected the LDC's application to implement a Straight Fixed Variable Rate Design. In Docket No. 98-KGSG-822-TAR, the order stated:

> *"13. The Commission rejects the argument that Federal Energy Regulatory Commission (FERC) Order 636 is relevant to this proceeding. The Commission finds the testimony of Staff witness Joe Williams to be persuasive on this issue. [Vol. 1, 176-77, 182; Vol. 2, 491-92, 516-17.1] The Commission concludes that the wholesale market addressed by the FERC Order is not comparable to the retail markets faced in Kansas by local distribution companies. The FERC Order focused on interstate pipeline concerns and its reasoning is not applicable to the situation at hand."*

Based on my experience, Atlanta Gas Light Company ("AGLC") is the only LDC that is allowed to employ the SFV rate design method to recover its distribution revenue requirement. The AGLC exception is mandated by legislation which strips the Georgia Public Service Commission of authority to order an alternative rate design. Based on my experience, other jurisdictions allow for reasonable fixed customer charges and reasonable fixed demand charges, but require that the bulk of the distribution revenue requirement be recovered over throughput.

Q. HAVE INDUSTRY CONDITIONS CHANGED TO JUSTIFY A MOVE TOWARD HIGHER FIXED CHARGES AND LOWER VOLUMETRIC CHARGES?

A. Industry changes should not affect the Commission's rate design policy. The most significant industry changes occurred at the pipeline level, not the retail distribution level. FERC decided to implement the SFV pipeline rate design whereby the pipelines were virtually guaranteed the recovery of their transportation revenue requirement, since nearly all of the revenue recovery was independent of throughput. It is foolish to accept a premise that industry restructuring affected the recovery of distribution costs. From a distribution level vantage point, not much has changed.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that UNS' rate design be rejected for the reasons stated in my testimony.

Q. ARE YOU PROPOSING A NEW RATE DESIGN?

A. No. The purpose of my rate design testimony is to provide an overview as to why UNS' proposal should be rejected. For specific calculation of rates, refer to Staff witness Ralph C. Smith's testimony.

DECOUPLING

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this Section is to address the proposed Throughput Adjustment Mechanism ("TAM") and to discuss Revenue Decoupling Mechanisms ("RDM") and provide my recommendation, which does not support the UNS proposal.

Q. WHAT IS A REVENUE DECOUPLING MECHANISM?

A. An RDM is a rate mechanism that separates earnings from throughput. One example of an RDM is the customer charge. It is a fixed rate that is independent of throughput and therefore, for example, is independent of weather variation. A similar mechanism is a purchased gas adjustment ("PGA") mechanism which protects the Company's earnings from price fly-ups regardless of throughput. Demand charges are also independent from throughput as capacity entitlements only consider contribution to a single peak day or are set by contract. Establishing base distribution rates using weather normalized billing units (volumes) also provides some earnings protection from weather sensitive throughput. An

SFV rate design is also an RDM because the fixed revenue requirement is recovered via demand charges.

Q. PLEASE DESCRIBE THE TAM THAT THE COMPANY IS PROPOSING.

A. The Company is proposing a mechanism, the TAM that would either reduce or increase the collection of volumetric margin revenues to match variations from anticipated usage levels. The TAM will either provide a credit or a surcharge to the existing customer's volumetric rate charge based on usage per customer ("UPC").

The reason for the TAM proposal is to provide the Company with a rate design that would align customer usage with anticipated revenues. Customer usage varies greatly due to changes in weather conditions. For example, if a winter was much colder than the normalized test year, the Company would over-recover revenues through the customer's volumetric charges. And if the weather was much warmer than normal, the Company would under-recover revenues through the customer's volumetric charge. The TAM would allow the Company to collect its anticipated revenues regardless of why average use per customer is different than anticipated. This mechanism would encourage the Company to promote conservation, but the TAM would discourage conservation by ratepayers because it implements surcharges that erode certain benefits ratepayers received due to conservation.

Q. HOW IS THE TAM CALCULATED?

A. The TAM is calculated by first establishing a base UPC. The base UPC is calculated by the test year throughput divided by the test year average number of customers. This is then compared to the actual UPC which is calculated as the actual throughput divided by the actual number of customers in a calendar year. The difference between the base UPC and the actual UPC is then multiplied by the test year's number of customers and the margin rate per therm to arrive at the required throughput adjustment in dollars. This dollar amount is then divided by the projected 12 month throughput ("therms") to arrive at the adjustment per therm.

The equations are as follows:

1. Throughput Adjustment (TA) = (Base UPC – Actual UPC) * Test year # of customers * Margin rate per therm; and
2. Adjustment per therm = TA divided by Projected 12 month throughput

Q. IS THERE AN EXAMPLE IN UNS' FILING?

A. Yes, refer to Company Exhibit TVL-2.

Q. ARE BASE RATES SET USING ACTUAL OR NORMALIZED VOLUMES?

A. Distribution rates are designed based on normalized volumes. The rates are intended to recover the distribution revenue requirement over normalized weather volumes. Recovering the distribution revenue requirement over normalized weather means that the Company is responsible for risk or good fortune from deviations from normal weather.

When weather is warmer than normalized volumes, the Company under-recovers its distribution revenue requirement because warm weather means less heat sensitive sales. Conversely, when the weather is cold, the Company over recovers its distribution revenue requirement.

The existing policy of designing rates over normalized volumes, without a RDM, has been the regulatory policy of the Commission. The consequences of the risk of deviations from normal weather has not precluded the Company from raising capital during its existence. Moreover, the symmetry of under recoveries attributable to warmer than normal weather and over recoveries from colder than normal weather is a traditional and reasonable allocation of weather risk between the Company and ratepayers.

Lastly, whether actual weather is more or less than normal weather, the impact on long-term recovery of the distribution revenue requirement will remain unaffected. Long-term recovery will not be affected as actual weather, whatever it may be, folded into the normalized volume calculation in succeeding base rate cases.

Q. IS THE COMPANY'S PROPOSAL PIECEMEAL RATEMAKING?

A. Yes. Another reason why the TAM should not be approved is that the TAM would be piecemeal ratemaking. The TAM deals with variations from expected use per customer. No other items in the ratemaking formula are considered in the TAM. There is no opportunity to search for offsetting adjustments such as cost of service reductions, changes in customer allocation factors and changes in the cost of capital, etc. Piecemeal ratemaking is frowned upon because all of the elements of the ratemaking formula are not considered.

Q. SHOULD DISTRIBUTION RATES BE FIXED BETWEEN RATE CASES?

A. Distribution-related costs should be fixed between rate cases to provide an incentive to keep costs down between base rate cases. This is the traditional ratemaking incentive to minimize costs between base rate cases. This is a much better regulatory approach than relying on the Company's good intentions to minimize costs.

The reason distribution rates are fixed between rate cases is that a powerful incentive exists for utilities to control costs between rate cases. Between rate cases a utility enjoys cost reductions attributable to increased efficiencies, but absorbs any cost increases. This is a basic tenet of public utility ratemaking that has been used for a considerable period of time with success which should not be diluted by the proposed TAM.

Q. ARE THERE ANY ADDITIONAL DISADVANTAGES TO THE TAM?

A. Yes. The TAM only addresses the recovery of margin, or approximately one-third of a customer's bill. Gas costs represent about two-thirds of a customer bill. Gas costs are also more volatile than distribution costs. Under TAM, customers could be facing high and volatile gas costs plus TAM surcharges.

Q. ARE YOU AWARE OF ANY SERIOUS PROBLEMS IN STATES THAT MAY HAVE IMPLEMENTED RDMS?

A. Yes. In the Direct Testimony sponsored by Mr. David E. Dismukes, Ph.D before the Michigan Public Service Commission (Case No. U-14893), Dr. Dismukes refers to the now terminated Electric Revenue Adjustment Mechanism implemented in Maine during the early 1990s (page 17). The adoption of the Mechanism coincided with a recession that resulted in lower sales and substantial revenue deferrals that amounted to $52 million by the end of 1992. Dr. Dismukes opposed an SFV rate design proposed by SEMCO ENERGY GAS COMPANY. The filing was eventually settled by January 2007, without approval of the decoupling-like proposal.

Also, I was involved in a January 2007 hearing regarding Public Service of New Mexico for a base rate and TAM (NMRPC Case No. 06-00210-00210-UT). My direct testimony addressed the regulatory acceptance of TAMs and noted that only 4 jurisdictions to date have adopted TAMs. The Company's TAM witness was Mr. Russell Feingold. In his rebuttal testimony, he was only able to cite 8 jurisdictions that have adopted a TAM and that 8 other gas utilities have proposed TAMs. (See the Rebuttal Testimony of Russell Feingold page 42 lines 1 to 8; NMRPC Case No. 06-00210-00210-UT).

Q. IS THE TAM SIMILAR TO AN AUTOMATIC ADJUSTMENT CLAUSE?

A. Yes. It is similar to a PGA which adjusts rates to recover for increased gas costs without a base rate case. The type of costs traditionally recovered in an automatic adjustment clause such as the TAM are skyrocketing and volatile costs, which if left unrecovered in a timely manner, could jeopardize a utility's financial heath.

Costs which are generally included in an adjustment rider are costs which are (1) large enough to jeopardize a utility's financial health (2) volatile and (3) substantially beyond a utility's control.

Based on my comments above, I believe that the TAM does not meet the three tests for inclusion in an automatic adjustment clause. First, traditional rate making has not left the Company in poor financial health. Second, non-gas costs are relatively stable from year to year and certainly not volatile to the same extent as gas costs. Third, non-gas costs are within management's control.

Q. DOES THE COMPANY ALREADY HAVE RDMs?

A. Yes. One example of a RDM is the customer charge. It is a fixed rate that is independent of throughput and therefore independent of weather variation. Another example is the PGA, which protects the Company's earnings from price fly-ups regardless of throughput. It should be noted that the TAM would collect revenues that are traditionally authorized but not guaranteed. The PGA collects expenses that have been incurred by the Company. Establishing base distribution rates using weather normalized billing units also provides some earnings protection from weather sensitive throughput.

Q. IS THERE ANY ARIZONA PRECEDENT?

A. The precedent may be found in the Opinion and Order of Southwest Gas' ("SW") last rate case. (Southwest Gas Decision No. 68487; Docket No. G-01551A-04-0876).

In that case, SW proposed a revenue decoupling mechanism called the Conservation Margin Tracker ("CMT"). The purpose of the CMT was the same as the TAM proposed in this case. The CMT tracked shortfall in billing units and imposed an annual surcharge on customers that insulated SW from the risk of declining volumes.

SW argued that the CMT would provide a more consistent revenue stream. SW argued that the consistent revenue stream produced by a revenue decoupling mechanism would insulate SW from risk. SW argued that borrowing costs would decline.

The Commission rejected SW's proposal, but indicated that meetings with Staff and other stakeholders should continue. The reasons for the rejection was that the CMT was inconsistent with the public interest and was not sound regulatory policy. (Southwest Gas; Decision No. 68487; Docket No.G-01551A-04-0876).

Q. WERE THERE ANY OTHER REASONS WHY THE COMMISSION REJECTED THE CMT FILED BY SOUTHWEST GAS?

A. Yes. On page 34 of the above referenced Decision, four additional issues are cited as reasons for rejecting SW's filing:

1. There is conflicting evidence in the record as to whether declining usage per customer will continue into the future, or for that matter, whether conservation efforts are the direct cause of SW's inability to earn its authorized return.
2. The likely effect of adopting the proposed CMT would be a disincentive to undertake conservation efforts because ratepayers would be required to pay for gas not used in prior years.
3. There is also concern that there could be a dramatic impact that could be experienced by customers faced with a surcharge for not using enough gas the prior year.
4. "The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case."

Q. HAS NARUC ADDRESSED THE DECOUPLING ISSUE?

A. I have reviewed the NARUC resolution, which I have attached as Staff Exhibit STF-SWR-3. The resolution does not endorse a revenue decoupling mechanism. The language of the resolution does not mention earnings variations attributable to variations from normal weather. The resolution mentions conservation, efficiency, and weatherization. There is a reference to demand responses in the gas markets, but the meaning of demand responses is too vague for a confident interpretation of its meaning.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING UNS' PROPOSED TAM?

A. Staff recommends that the TAM be rejected because of the following reasons:

1. The TAM would shift the risk of declining usage attributable to weather and economics from UNS shareholders to ratepayers.
2. The TAM would be piecemeal ratemaking.
3. The TAM would discourage retail customers from undertaking conservation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNS Gas Inc. rate Case; Docket No. G-04204A-06-0463
FRONT END LOAD ANALYSIS

	Residential R10	Residential Cares R12	Small Comm Serv C20	Large Comm Serv & Comm Trans C22	Sm. Industrial I30	Large Industrial & Industrial Trans I32	Sm. Public Authority PA-40	Lg. Public Authority and Public Authority Trans PA-42	Special Gas Light PA-44	Irrigation IR-60
# of Customers										
Customer Charge (Sum: Apr - Nov) or all year	973,311	33,620	132,098	222	150	238	12,827	117	866	66
Customer Charge (Win: Dec-Mar)	489,824	16,548								
CUSTOMER CHARGE										
CURRENT										
Customer Charge (Sum: Apr - Nov) or all year	$ 7.00	$ 7.00	$ 11.00	$ 85.00	$ 11.00	$ 85.00	$ 11.00	$ 85.00	$ 13.57	$ 11.00
Customer Charge (Win: Dec-Mar)	$ 7.00	$ 7.00								
PROPOSED										
Customer Charge (Sum: Apr - Nov) or all year	$ 20.00	$ 20.00	$ 20.00	$ 120.00	$ 20.00	$ 120.00	$ 20.00	$ 120.00	$ 16.47	$ 20.00
Customer Charge (Win: Dec-Mar)	$ 11.00	$ 11.00								
% of Increase										
Customer Charge (Sum: Apr - Nov) or all year	185.71%	185.71%	81.82%	41.18%	81.82%	41.18%	81.82%	41.18%	21.37%	81.82%
Customer Charge (Win: Dec-Mar)	57.14%	57.14%								
REVENUES GENERATED BY CUSTOMER CHARGE										
Current Revenues	$ 10,241,949	$ 351,177	$ 1,453,077	$ 18,850	$ 1,655	$ 20,256	$ 141,098	$ 9,909	$ 11,758	$ 725
Proposed Revenues	$ 24,854,292	$ 854,430	$ 2,641,958	$ 26,612	$ 3,010	$ 28,596	$ 256,541	$ 13,989	$ 14,270	$ 1,317
Customer Charge Revenue Increase	$ 14,612,343	$ 503,254	$ 1,188,881	$ 7,762	$ 1,354	$ 8,341	$ 115,443	$ 4,080	$ 2,513	$ 593
Total Revenue Increase	$ 6,582,656	$ 205,963	$ 1,801,410	$ 139,754	$ 23,054	$ 416,661	$ 322,521	$ 134,687	$ 15,220	$ 4,975
% of Total Revenue Increase	**221.98%**	**244.34%**	**66.00%**	**5.55%**	**5.88%**	**2.00%**	**35.79%**	**3.03%**	**16.51%**	**11.92%**

Source:
Total Number of Customers is provided from Company's exhibit filename: RUCO1.10UNSGASScheduleHSupportv2
Current and Proposed Customer charges are provided from Company's *Schedule H-3*
Total Revenue Increase is provided from Company's Schedule H-2 page 2

UNS Gas Inc. rate Case; Docket No. G-04204A-06-0463
Calculation of Customer Charge for each Rate Class

Acct. No.	Description	Total	Residential R10	Residential Cares R12	Small Comm Serv C20	Large Comm Serv C22	Comm Transporatation	Sm. Industrial I30	Large Industrial I32	Industrial Transportation	Sm. Public Authority PA-40	Lg. Public Authority PA-42	Public Authority Transportation	Special Gas Light PA-44	Irrigation IR-60
	Distribution Plant														
380	Services	72,951,925	63,363,598	2,807,193	5,785,431	9,255	8,126	6,755	6,320	9,932	944,140	5,267	2,709	0	3,200
380	Services ACQ ADJ	(6,640,414)	(5,767,641)	(255,523)	(526,616)	(842)	(740)	(615)	(575)	(904)	(85,940)	(479)	(247)	0	(291)
381	Meters	13,255,870	10,184,736	451,214	2,422,162	23,221	20,389	1,258	14,000	24,000	105,023	528	8,000	0	1,340
381	Meters ACQ ADJ	(1,160,990)	(892,010)	(39,519)	(212,140)	(2,034)	(1,786)	(110)	(1,226)	(2,102)	(9,198)	(46)	(701)	0	(117)
382	Meter Installation	6,788,598	5,215,808	231,076	1,240,438	11,892	10,442	644	7,170	12,291	53,785	271	4,097	0	686
382	Meter Installation ACQ ADJ	(744,797)	(572,241)	(25,352)	(136,092)	(1,305)	(1,146)	(71)	(787)	(1,348)	(5,901)	(30)	(449)	0	(75)
383	REGULATORS	2,628,662	2,019,651	89,476	480,319	4,605	4,043	249	2,776	4,759	20,826	105	1,586	0	266
383	REGULATORS - ACQ ADJ	(178,700)	(137,299)	(6,083)	(32,653)	(313)	(275)	(17)	(189)	(324)	(1,416)	(7)	(108)	0	(18)
384	REGULATOR INSTALLATIONS	1,163,556	893,982	39,606	212,609	2,038	1,790	110	1,229	2,107	9,219	46	702	0	118
384	REGULATOR INSTALLATIONS - ACQ ADJ	(82,263)	(63,204)	(2,800)	(15,031)	(144)	(127)	(8)	(87)	(149)	(652)	(3)	(50)	0	(8)
385	INDUSTRIAL MEAS. EQUIP	1,230,284	0	0	1,004,540	32,610	24,458	1,689	16,305	27,175	92,876	13,588	16,305	0	739
385	INDUSTRIAL MEAS. EQUIP - ACQ ADJ	(106,446)	0	0	(66,916)	(2,622)	(2,116)	(146)	(1,411)	(2,351)	(8,036)	(1,176)	(1,411)	0	(64)
	Total Customer Related Distr. Plant	89,105,284	74,245,379	3,289,288	10,136,050	76,162	63,059	9,738	43,525	73,085	1,114,727	18,063	30,434	0	5,773
	Total Distribution Plant	214,687,170	143,293,346	6,091,274	36,776,343	1,189,484	2,786,553	428,587	1,852,028	10,687,634	7,113,030	1,035,141	3,300,492	75,531	57,727
	% of Customer Related Distr. Plant	41.50%	51.81%	54.00%	27.56%	6.40%	2.26%	2.27%	2.35%	0.68%	15.67%	1.74%	0.92%	0.00%	10.00%
	Total Distribution Plant Accumulated Depr.	59,890,270	41,081,169	1,757,564	9,959,073	301,136	686,611	105,258	456,485	2,607,606	1,839,532	255,490	807,356	18,351	14,639
	Portion attributable to Customer Related	24,857,282	21,285,615	949,085	2,744,853	19,282	15,538	2,392	10,728	17,832	288,284	4,458	7,445	0	1,464
	Net Distribution Plant	**64,248,002**	**52,959,765**	**2,340,203**	**7,391,197**	**56,880**	**47,521**	**7,347**	**32,797**	**55,254**	**826,442**	**13,605**	**22,990**	**0**	**4,309**
	Carrying Cost (Customer related net plant * 18%)	**$ 11,564,640**	**$ 9,532,758**	**$ 421,237**	**$ 1,330,415**	**$ 10,238**	**$ 8,554**	**$ 1,322**	**$ 5,904**	**$ 9,946**	**$ 148,760**	**$ 2,449**	**$ 4,138**	**$ -**	**$ 776**
	Expense Accounts														
878	METER EXPENSE	1,349,114	1,036,550	45,922	246,515	2,363	2,075	128	1,425	2,443	10,689	54	814	0	136
879	CUSTOMER INSTALL EXP	539,082	414,187	18,350	98,503	944	829	51	569	976	4,271	21	325	0	54
892	MAINT. OF SERVICES	465,066	403,941	17,896	36,882	59	52	43	40	63	6,019	34	17	0	20
893	MAINT. OF METER	167,015	128,321	5,685	30,518	293	257	16	176	302	1,323	7	101	0	17
901	SUPERVISION	74,309	66,186	1,584	5,925	7	4	7	4	8	574	3	3	1	3
902	METER READING EXPENSE	719,037	628,450	27,842	56,794	84	47	66	55	94	5,502	42	31	0	31
903	CUST RECORDS & COLLECT	5,462,173	4,904,509	75,313	437,313	430	240	507	280	481	42,364	213	160	120	240
905	MISC CUST ACCTS EXP	34,381	29,549	590	2,902	15	186	3	3	683	238	1	208	1	2
906	CUSTOMER SERVICE & INFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0
907	SUPERV. CUSTOMER SERV.	14,743	12,856	603	1,164	1	1	1	1	1	113	1	0	0	1
908	CUSTOMER ASSISTANCE	(34,228)	(29,848)	(1,400)	(2,702)	(3)	(1)	(3)	(2)	(3)	(262)	(1)	(1)	(1)	(1)
909	INFO & INSTRUCTIONAL ADVERT.	65,794	57,374	2,692	5,193	5	3	6	3	6	503	3	2	1	3
910	MISC. CUST. SERV. & INFO.	22,602	19,709	925	1,784	2	1	2	1	2	173	1	1	0	1
	Total Customer Related Expenses	**8,879,088**	**7,671,784**	**196,002**	**920,792**	**4,201**	**3,693**	**828**	**2,557**	**5,056**	**71,507**	**377**	**1,662**	**123**	**508**
	Total Carrying Cost & Related Customer Exp.	$ 20,443,728	$ 17,204,542	$ 617,238	$ 2,251,207	$ 14,439	$ 12,246	$ 2,150	$ 8,460	$ 15,001	$ 220,267	$ 2,826	$ 5,800	$ 123	$ 1,283
	Year End # of Customers	138,340	120,636	5,660	10,919	11	6	13	7	12	1,058	5	4	3	6
	Number of Bills per Year	1,660,074	1,447,629	67,925	131,027	129	72	152	84	144	12,693	64	48	36	72
	Customer Cost/ Bill		$ 11.88	$ 9.09	$ 17.18	$ 111.98	$ 170.09	$ 14.14	$ 100.72	$ 104.18	$ 17.35	$ 44.26	$ 120.83	$ 3.43	$ 17.83

Source
Year End # of Customers is provided from the Company's cost of service study; Schedule G-7 Factors (CUST10)

Resolution on Gas and Electric Energy Efficiency

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review and reconsider the level of support and incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response in both gas and electricity markets; *and*

WHEREAS, The National Petroleum Council (NPC), in its September 25, 2003 report on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, found that greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility and recommended all sectors of the economy work toward improving demand flexibility and efficiency; *and*

WHEREAS, The NPC, in its report, identified key elements of the effort to maintain and continue improvements in the efficient use of electricity and natural gas, including (but not limited to):

(i) enhanced and expanded public education programs for energy conservation, efficiency, and weatherization,

(ii) DOE identification of best practices utilized by States for low-income weatherization programs and to encourage nation-wide adoption of these practices,

(iii) a review and upgrade of the energy efficiency standards for buildings and appliances (to reflect current technology and relevant life-cycle cost analyses) to ensure these standards remain valid under potentially higher energy prices

(iv) promote the use of high-efficiency consumer products including advanced building materials, Energy Star appliances, energy "smart" metering and information control devices

(v) on-peak electricity conservation to minimize the use of gas-fired electric generating plants,

(vi) the use of combined-cycle gas-fired electric generating units instead of less-efficient gas-fired boilers, and

(vii) clear natural gas and power price signals; and

(viii) remove regulatory and rate structure incentives to inefficient use of natural gas and electricity; and

WHEREAS, The NARUC, at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit"* which encouraged the NARUC Natural Gas Task Force, to review (among other things) the findings and recommendations in the NPC report that have regulatory implications for State commissions for improving and promoting energy efficiency and conservation initiatives, including consumer outreach and education, review of regulatory throughput incentives*; and*

WHEREAS, The American Council for an Energy-Efficient Economy ("ACEEE"), in its December 2003 report on *Responding to the Natural Gas Crisis: America's Best Natural Gas Energy Efficiency Programs*, (i) identified States and utilities with programs that many would consider best practice or model programs for all types of natural gas customers and all principal natural gas end-use technologies, and (ii) found that these programs are concentrated in relatively few States and regions and could be expanded in other parts of the country to great benefit; *and*

WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the ACEEE have recently adopted a Joint Statement noting that traditional rate structures often act as disincentives for natural gas utilities to aggressively encourage their customers to use less gas. Therefore, the NRDC, AGA, and the ACEEE have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 2004 Summer Meetings in Salt Lake City, Utah, encourages State commissions and other policy makers to support the expansion of natural gas energy efficiency programs and electric energy efficiency programs, including those designed to promote consumer education, weatherization, and the use of high-efficiency appliances, where economic, and to address regulatory incentives to address inefficient use of gas and electricity; *and be it further*

RESOLVED, That the Board of Directors of the NARUC, encourages State and Federal policy makers to: (i) review and upgrade the energy efficiency standards for buildings and appliances, where economic, to ensure these standards remain valid under potentially higher energy prices, and (ii) promote the use of high-efficiency consumer products, where economic, including advanced building materials, Energy Star appliances, and energy "smart" metering and information control devices; *and be it further*

RESOLVED, That Board of Directors of NARUC encourages State Commissions to review and consider the recommendations contained in the enclosed *Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy-Efficient Economy; and be it further*

RESOLVED, That the Board of Directors of the NARUC recognizes that the best approach towards promoting gas energy efficiency programs and electric energy efficiency programs for any single utility, State or region may likely depend on local issues, preferences and conditions.

Sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, and Committee on Energy Resources and the Environment
Adopted by the NARUC Board of Directors July 14, 2004

EXHIBIT
ALL-STATE LEGAL®
S-24
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

SURREBUTTAL

TESTIMONY

OF

STEVEN W. RUBACK

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

APRIL 4, 2007

Q. Please state your name.

A. My name is Steven W. Ruback.

Q. Have you filed direct testimony in this case?

A. Yes, I have.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of D. B. Erdwurm regarding the UNS proposed Throughput Adjustment Mechanism ("TAM") and customer charges.

Q. Mr. Erdwurm on page 15, lines 17 to 27, argues that the "company has a strong incentive to control costs with or without the TAM". Would you please respond?

A. Mr. D. B. Erdwurm supports his argument by noting that the TAM will not recover costs not already included in rates. Mr. Erdwurm treats the issue as either black or white. My point is that any incentives for the Company to control costs will be seriously diluted as a result of the TAM. The TAM recovers the difference in costs that is attributable to deviations from the billing units used to set rates attributable to weather considerations, general economic conditions in the service area and conservation. UNS' proposal would water down the incentive to control costs because any under-recovery will be offset by the operation of the TAM.

Q. Mr. Erdwurm on page 15, lines 25 to 27 argues that the TAM true-up does not provide a guarantee that the company will earn its authorized rate of return". Would you please respond?

A. A true-up reallocates the risk of under recovery of costs from UNS to customers. The effect of any rate design true-up is to provide dollar for dollar cost recovery. The risk of under recovery of costs is eliminated because any recovery shortfall attributable to weather variations is recovered on a dollar for dollar basis via the TAM true-up. Once again, this is not a black or white issue. If the TAM does not provide a guaranteed rate of return, the TAM certainly and substantially reduces the risk of under recovery of costs and, therefore, reallocates the regulatory risk from an opportunity to earn an authorized rate of return to a situation where recovery of the authorized rate of return is practically assured.

Q. Mr. Erdwurm on page 16 lines 9 to 26 argues that the TAM decision in the Southwest Gas Corporation rate case in decision No. 68487 was not denied by the Commission. Would you please respond?

A. This criticism is much to do about nothing. The fact is that Southwest Gas Corporation proposed a revenue decoupling mechanism in its last rate case which was not approved. Instead, the Commission suggested discussions among the stakeholders, but that is all. There was no commitment on behalf of the Commission that a revenue decoupling mechanism would be approved even if the stakeholders held different views. The issue was tabled for future consideration. The revenue decoupling mechanism is not part of Southwest Gas Corporation's approved tariff. I would also point out that the Commission specifically encourages discussions with respect to conservation to the benefit of all stakeholders.

Q. Mr. Erdwurm on page 17, lines 1 to 22, argues that the American Gas Association supports revenue decoupling mechanisms. Are you surprised?

A. No, I am not surprised by AGA's position. The statement made to the Senate Energy and Natural Resources Committee was motivated solely by self interest. The AGA Executive Summary, provided as Exhibit DBE-2, notes that "The American Gas Association represents 200 local energy companies that deliver natural gas to more than 64 million homes, businesses and industries throughout the United States." The AGA is an industry group of local gas distribution utilities. It would be a mistake to assume that the AGA's interests are aligned with those of the Commission and other stakeholders.

Q. Mr. Erdwurm on page 17 line 24 to page 18 line 20, argues that the National Defense Counsel and the American Council for An Energy-Efficient Economy support decoupling. Would you please respond?

A. After reading Exhibit DBE-3 it appears that the National Defense Counsel and the American Council for An Energy-Efficient Economy are primarily interested in conservation and energy efficiency. As noted earlier, UNS' proposal extends to weather and general economic conditions. It should be noted that the Commission had access to the Joint Statement in the Southwest Gas Rate Case as Exhibit No. SMF-2, and still concluded that approval of the decoupling mechanism was not in the public's interest.

Q. Mr. Erdwurm on page 18, line 22, refers to a more recent NARUC resolution supporting decoupling tariffs. Please comment.

A. The November 16, 2005 NARUC Resolution provided as Exhibit DBE-4 is limited to conservation and energy efficiency. UNS' proposal goes much farther by including weather variations and general economic conditions in its proposed revenue decoupling mechanism. The Resolution resolves that NARUC encourages rate design reviews that "will encourage energy conservation and energy efficiency" and should not, in my judgment be interpreted as support for revenue decoupling proposals such as proposed by UNS.

Q. Mr. Erdwurm on page 19, lines 12 to line 15, notes that ten states have adopted decoupling mechanisms. Please comment.

A. An alternative interpretation is that 40 states have not adopted decoupling mechanisms. The regulatory support offered by Mr. Erdwurm shows that states approving revenue decoupling mechanisms are in the minority.

Q. On page 19, lines 1-10, Mr. Erdwurm characterizes the early 1990s economic recession in Maine and how it impacted the TAM-like Electric Revenue Adjustment Mechanism ("ERAM") as something that could not happen with the TAM.

A. The fact that apparently escapes Mr. Erdwurm is that the ERAM, like the TAM, had no adjustments for changes in regional activity. The adoption of the ERAM coincided with a recession that resulted in lower sales levels and substantial revenue deferrals that reached $52 million at the end of 1992. The ERAM was viewed by many as a mechanism that shielded Central Maine Power ("CMP") from the economic impact of the recession rather than furthering the intended energy conservation incentives. CMP's ERAM was terminated on November 30, 1993.

Q. On page 9, line 9 to page 10, line 23, of Mr. Erdwurm's rebuttal testimony, he argues that natural gas distribution system costs are fixed costs largely supported by volumetric rates. Is this a new argument?

A. No. This is not a new argument. The Company's direct testimony includes the same arguments advanced to support higher customer charges.

Q. Even though it may not be a new argument, would you please respond?

A. I do not disagree that natural gas distribution system costs are fixed costs largely supported by volumetric rates. Mr. Erdwurm fails to understand that, according to rate design practice, fixed costs do not have to be recovered with fixed charges. The only jurisdiction that I am familiar with that allows all fixed costs to be recovered from fixed charges is Georgia. Atlanta Gas Light Company has such a Straight-Fixed-Variable rate design, but the Georgia Legislature stripped the Commission of rate design authority and mandated the Straight-Fixed-Variable rate design.

Natural gas distribution systems have long been recognized as fixed costs systems, and Commissions throughout the Country have designed rates which recover some amount of customer costs in a fixed customer charge and the remainder of the revenue requirement from demand charges and volumetric rates. This rate design has been used for all natural gas distribution systems with the exception of Atlanta Gas. This rate design is not limited to natural gas distribution utilities. Electric utilities also routinely recover fixed costs from volumetric charges. The problem that Mr. Erdwurm identifies is an old issue. I disagree that the Company's proposal does not violate long-standing regulatory principles. In my opinion, UNS' customer charge proposals are not consistent with industry rate design standards.

Q. Is cost of service the sole criterion for class revenue requirements and rate design?

A. I take umbrage with his comment that Staff did not consider cost of service principles in arriving at its recommendation. Mr. Erdwurm apparently does not understand that rates are not set by cost of service alone. Cost of service is an important rate design criterion, but not the sole criterion. The results of an allocated cost of service study are the starting point for rate design. Regulators have traditionally used gradualism, value of service, public acceptability and other non-cost of service criteria. Moreover, regulators have not assigned specific weightings to any one criterion, recognizing that rate design is an art, not a strict mathematical exercise without the application of informed judgment.

Q. On page 12, line 18, of Mr. Erdwurm's rebuttal testimony, he argues that telephone, cable television and internet service have moved away from volumetric rates. Is this relevant?

A. No. There are important distinctions to be made. First, the telephone industry is highly competitive and rates should reflect competitive considerations, not cost of service considerations. Internet service is also competitive, and price must be competitive with other service suppliers regardless of cost. Cable television tends to have a monopoly in a specific geographic area, but cable television is not an essential utility service.

Q. Does that conclude your surrebuttal testimony?

A. Yes.

EXHIBIT
S-25
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
MIKE GLEASON
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER
GARY PIERCE
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC., DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC	DOCKET NO. G-04204A-05-0831

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

FEBRUARY 9, 2007

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data
- Rate base, including construction work in progress
- Test year revenues (including number of customers and usage) and expenses.
- Depreciation rates
- Rules and regulations, including line extensions.

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $9.647 million is overstated. I recommend that UNS Gas be authorized a base rate increase of $4.721 million.

- The following adjustments to UNS Gas' proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base

Adj. No.	Description	Original Cost Increase (Decrease)	Fair Value Increase (Decrease)
B-1	Remove Construction Work in Progress	$ (7,189,231)	$ (7,189,231)
B-2	Remove GIS Deferral	$ (897,068)	$ (897,068)
B-3	Cash Working Capital - Lead/Lag Study	$ 770,960	$ 770,960
B-4	Accumulated Deferred Income Taxes	$ 195,336	$ 195,336
	Total of Staff Adjustments	**$ (7,120,003)**	**$ (7,120,003)**
	UNS Proposed Rate Base	$ 161,661,361	$ 191,177,715
	Staff Proposed Rate Base	**$ 154,541,358**	**$ 184,057,712**

- The following adjustments to UNS Gas' proposed revenues, expenses and net operating income should be made:

Summary of Staff Adjustments to Net Operating Income

Adj. No.	Description		Increase (Decrease)
C-1	Revenue Annualization	$	62,896
C-2	Weather Normalization	$	1,205
C-3	Adjustment to Bad Debt Expense	$	(776)
C-4	Remove Depreciation & Property Taxes for CWIP	$	222,981
C-5	Remove Amortization of Deferred GIS Cost	$	183,606
C-6	Incentive Compensation and SERP	$	164,204
C-7	Emergency Bill Assistance Expense	$	(13,263)
C-8	Remove Nonrecurring Severance Payment Expense	$	32,167
C-9	Overtime Payroll Expense	$	75,531
C-10	Payroll Tax Expense	$	8,201
C-11	Nonrecurring FERC Rate Case Legal Expense	$	190,992
C-12	Property Tax Expense	$	49,300
C-13	Worker's Compensation Expense	$	21,020
C-14	Membership and Industry Association Dues	$	16,498
C-15	Fleet Fuel Expense	$	32,199
C-16	Postage Expense	$	70,671
C-17	Interest Synchronization	$	118,085
Total of Staff's Adjustments to Net Operating Income		**$**	**1,235,516**
	Adjusted Net Operating Income per UNS Gas	$	8,428,981
	Adjusted Net Operating Income per Staff	**$**	**9,664,497**

- The new depreciation rates proposed by UNS Gas presented in Dr. White's direct testimony Attachment REW-2 should be adopted for use in this case. The depreciation rates proposed by UNS Gas were developed in a manner that is consistent with the Commission's rules for depreciation rates.

- Each of the new depreciation rates proposed by UNS Gas should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

- The Company's proposed changes to Rules and Regulations in its tariff should be adopted, as discussed in my testimony.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst (CRRA). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts (SURFA). I have also been a member of the

American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 27 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Most recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and concerning APS's proposed depreciation rates in Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving APS base rates and other matters.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the revenue requirement and selected other issues, including new depreciation rates, and rules and regulation changes proposed by UNS Gas, Inc. ("UNS Gas") in the current rate case.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-6 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNS Gas?

A. UNS Gas is requesting a revenue increase of $9.647 million, or approximately 7 percent. UNS Gas witness James Pignatelli's direct testimony at pages 2-3 attributes the need for the requested increase primarily to increased growth in UNS Gas' service territory and the related increases in capital expenditures and operating costs.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of $4.721 million.

<u>A. Test Year</u>

Q. What test year is being used in this case?

A. UNS Gas' filing is based on the historic test year ended December 31, 2005. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-4 and net operating income adjustment Schedules C-1 through C-17.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. The schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 8.12%, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience. Schedule D uses the capital structure and cost rates recommended in the prefiled testimony of Mr. Parcell. The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor (GRCF). The derivation of the GRCF is shown on Schedule A-1.

Q. What is shown on Schedule B?

A. Page 1 of Schedule B presents UNS Gas's proposed adjusted test year Original Cost and Fair Value rate base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNS Gas Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1.

Q. How was the fair value basis of rate base determined?

A. The Fair Value basis was determined by averaging Original Cost and reconstruction cost new depreciated (RCND) information.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNS Gas's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to UNS Gas's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments are discussed in this testimony. Schedules C-1 through C-17 provide further support and calculations for the net operating income adjustments I am recommending.

Q. What did your review of UNS Gas' filing indicate?

A. As shown on Schedule A, based on the rate of return recommended by Staff witness Parcell and the adjustments to UNS Gas' rate base and net operating income recommended by myself and other Staff witnesses, I have calculated a revenue requirement deficiency of $4.721 million for UNS Gas.

III. RATE BASE

Q. Have you prepared a schedule that summarizes staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNS Gas' proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

Summary of Rate Base	UNS Gas	Staff	Difference
Original Cost Rate Base	$ 161,661,361	$ 154,541,358	$ (7,120,003)
Fair Value Rate Base	$ 191,177,715	$ 184,057,712	$ (7,120,003)

B-1, Construction Work in Progress

Q. Please explain the adjustment shown on Schedule B-1.

A. UNS Gas has proposed to include $7.189 million of Construction Work in Progress (CWIP) in rate base. Staff adjustment B-1 removes that amount of CWIP from rate base.

Q. Please discuss UNS Gas' reasons for requesting the inclusion of CWIP in rate base.

A. As described in the testimony of UNS Gas witness Kentton Grant, the Company believes that inclusion of CWIP in rate base is necessary to preserve the financial integrity of the Company. Mr. Grant indicates that, as reflected in the Company's rate application, rate base treatment of the $7.189 million test year CWIP balance provides UNS Gas with approximately $1.5 million in additional annual revenues. He states that denial of this requested rate treatment would have a material adverse impact on the Company's rate relief and future earnings, and would make it difficult for the Company to attract new capital on reasonable terms. The Company has been experiencing robust growth and expects to need access to outside capital to fund system growth and capital improvements. Mr. Grant also states that inclusion of CWIP in rate base is one of the few available tools to help mitigate the effects of regulatory lag. He suggests further that, by including CWIP in rate base in this proceeding, the time period between this rate case and the next rate filing by UNS Gas will hopefully be extended. He indicates that if the Company's proposed rate base treatment of CWIP is denied, the authorized rate of return should be increased, and the Commission should consider an adjustment for plant placed into service after the test year. He points out that the Commission has, on occasion, allowed the inclusion of post test year plant in rate base.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base.

Q. Does Staff agree with the proposal of UNS Gas to include CWIP in rate base in the current case?

A. No. In general, Staff does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For a number of reasons, including the following, Staff does not support UNS Gas' request for rate base inclusion of CWIP in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.

2) The CWIP was not in service at the end of the test year. As of December 31, 2005, the construction projects were not serving customers.

3) The Company has not demonstrated that its December 31, 2005 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for mains, services and meters related to serving customer growth, i.e., to be revenue producing. Test year revenues have been annualized to year-end customer levels. However, revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced.

4) While the Company has stated that inclusion of CWIP in rate base could result in deferring the filing of its next rate case, the Company has made no specific enforceable commitments to a filing moratorium period.

Q. Please elaborate on how including CWIP in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in delivering gas service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Gas rate case, the test year is calendar 2005, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such CWIP should be excluded from rate base.

Furthermore, some of the facilities that are being constructed and are included in CWIP will be used subsequent to the 2005 test year to serve additional customers. It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process. Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test period. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule. In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base. It is not appropriate to include the CWIP in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the 2005 test year.

Q. How does UNS Gas accrue a return on construction projects?

A. UNS Gas accrues a return, representing its financing costs during the construction period, called Allowance for Funds Used During Construction (AFUDC). This AFUDC return accounts for the utility's financing cost during the construction period. Then, when the plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Does Staff agree with UNS Gas' alternative proposal to include post-test year plant additions in rate base, if the inclusion of CWIP in rate base is denied?

A. No. For similar reasons to those described above, Staff does not agree with UNS Gas' proposed alternative of including post-test year plant in rate base.

Q. Is another witness for Staff addressing certain aspects of UNS Gas' request for inclusion of CWIP in rate base?

A. Yes. Staff's rate of return witness, Dave Parcell, is addressing the determination of a fair rate of return that would allow UNS Gas to attract new capital on reasonable terms. In making his cost of capital recommendations, Mr. Parcell has been made aware of and has taken into consideration UNS Gas' proposal to include CWIP in rate base and Staff's recommendation that CWIP not be included in rate base in this case.

Q. Does Staff's adjustment to remove CWIP from rate base affect UNS Gas's expenses?

A. Yes. UNS Gas had proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Gas proposed increases to depreciation and property tax expense. Consistent with Staff's recommendation that CWIP not be included in rate base, Staff adjustment C-4, which is described in a subsequent section of my testimony, removes the related UNS Gas adjustments for depreciation and property tax expense.

B-2, Global Information System (GIS) Deferral

Q. Please explain the adjustment shown on Schedule B-2.

A. UNS Gas has proposed to include $897,068 in rate base for a deferral of costs related to its Geographic Information System (GIS). Staff adjustment B-2 removes that amount of deferred costs from rate base.

Q. What functions and benefits does the UNS Gas GIS provide?

A. UNS Gas witness Gary Smith's direct testimony at pages 6-7 indicates that the GIS helps UNS Gas maintain an accurate, up-to-date record of its facilities. His testimony also indicates that the GIS helps the Company comply with state and federal laws and provides numerous benefits to the Company and its customers including:

- Maintaining accurate maps of facilities
- Improving response time
- Promoting better-informed decisions
- Facilitating faster completion of map changes and more timely reporting of facility assets
- Enabling employee field access of up-to-date GIS maps, allowing them to locate lines more quickly and accurately.

Q. Please describe how UNS Gas has accounted for costs related to its GIS.

A. As described in the Company's response to RUCO data request 2.15[1], the UNS Gas' GIS entered service on July 1, 2001. The GIS resides in Account 391 per the FERC Uniform System of Accounts (USOA). The original cost of the GIS was $1,158,035 and has been depreciated at a rate of 13.92% per year[2]. This part of the Company's accounting is not controversial.

However, the Company's proposal to add $897,068 in a pro forma adjustment to rate base for a subsequent questionable deferral of costs related to its GIS and to prospectively amortize such a deferred cost over a three-year period is controversial, and has been determined by Staff to be inappropriate, as described below.

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[1] Copies of UNS Gas' responses to data requests referenced in my testimony are provided in Attachment RCS-5.
[2] UNS Gas has depreciated Account 391.20, Computer Equipment – Desktop PCs, at 13.89 percent per year. In the current case, UNS Gas is proposing a five-year amortization for that account. Staff has not taken exception to this UNS Gas request.

Q. Please describe how the deferral of costs related to the UNS Gas GIS occurred, and how UNS Gas' deferral accounting for such costs was ultimately determined, by the Company itself, to be inappropriate.

A. During 2003-2005, UNS Gas undertook a project to locate and assign global positioning system (GPS) information to its existing service lines in order to update the UNS Gas GIS. The project was undertaken as a result of an Arizona Corporation Commission compliance audit, which found that: "Maps available at the time of the audit and used by locating, leak survey, construction and emergency personnel fail to include all service lines." As explained in UNS Gas witness Gary Smith's testimony, at page 6, a 2002 Annual Commission Pipeline Safety Audit had concluded that the Company needed to complete mapping of its service lines in a more timely basis. The Company enlisted outside contractors to help it comply with this recommendation

UNS Gas initially accounted for these costs as capital costs. The Company partially placed the project into service in 2005, but assigned it an in-service date of 12/31/03, with catch-up depreciation of approximately $50,000 recognized as of 8/31/05. The total cost of the project was approximately $897,000, with 83% of the cost, or $747,000, paid to Front Line Energy for locating and "GPS-ing" the lines.

In 2005, UNS Gas concluded that, absent an ACC order to defer such costs, the accounting treatment of the costs would need to be consistent with Generally Accepted Accounting Principles (GAAP). The FERC USOA does not specifically prescribe a procedure to be used in accounting for the costs of developing computer software. However, FERC issued an Order on Accounting for Pipeline Assessment Costs in Docket No. A105-1-000 on 6/30/05, which contained a specific reference to the AICPA's Accounting Standards Executive Committee (AcSEC) Statement of Position ("SOP") 98-

1, Accounting for the Costs of Computer Software Developed or Obtained for Internal Use ("SOP 98-1"). Paragraph 22 of SOP 98-1 states, in pertinent part that:

> "The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, <u>creation of new/additional data</u>, and conversion of old data to the new system. Data conversion often occurs during the application development stage. Data conversion costs, except as noted in Paragraph 21, <u>should be expensed as incurred.</u>"[3]

As a result of this interpretation by UNS Gas of the proper accounting, the Company determined that certain misstatements of the financial statements as of December 31, 2004 had occurred. These included an overstatement of Total Utility Plant of $872,000 and an understatement of cumulative Other Operations and Maintenance of $872,000.

Q. Please discuss UNS Gas' reasons for requesting the inclusion of the GIS costs in rate base.

A. As explained in the testimony of UNS Gas witness Gary Smith and in the Company's workpapers for the adjustment, UNS Gas is asking to recover a return on and a return of this investment because the expenditures were made to insure compliance with ACC requirements and provide benefits to present and future ratepayers of the utility.

Q. Please discuss Staff's reasons for removing the GIS cost from rate base.

A. This cost was required to be expensed under GAAP. It is of a one-time, non-recurring nature. Had it been expensed properly by UNS Gas in the appropriate periods, the vast majority of the GIS cost that UNS Gas deferred would have been expensed prior to the

[3] Emphasis as supplied in UNS Gas' October 3, 2005 Memo to File re 2003-05 UNS Gas "GPS and Locate" Costs. See Attachment RCS-5.

2005 test year. UNS Gas did not request Commission pre-approval for recovery or cost deferral, and therefore could not defer the costs as a regulatory asset.

The majority of the cost that UNS Gas is requesting was incurred prior to the 2005 test year, and should have been expensed by the Company in periods prior to 2005. In the UNS Gas memo dated October 3, 2005, which I have reproduced in Attachment RCS-5, the Company concluded (at memo page 4 of 7) that "the misstatements to the 2003 and 2004 UNS income statements are deemed to be immaterial" and "the misstatements to the December 31, 2004 balance sheets are deemed to be immaterial as the misstatement to Total Utility Plant was .02% and to Total Assets of .03%" At page 5 of 7 of that memo, the Company concludes that: "Due to the immateriality of the error to UNS, we do not believe that the error masks a change in earnings, does not hide a failure to meet analysts' consensus expectations for the enterprise, it does not change income to a loss, it does not affect compliance with regulatory requirements, it did not increase management compensation and does not conceal an unlawful transaction." At page 7 of 7 of the memo, the Company concludes that: "We have carefully considered both quantitative and qualitative aspects of the misstatement of the UNS Gas 'GPS and Locate' costs and believe that the error is not material to the respective financial statements for all periods considered. Accordingly, it is deemed acceptable to record the correcting adjustment in the third quarter of 2005." In the third quarter of 2005, UNS Gas recorded an adjustment to remove the deferred costs from its balance sheet and to charge them to operating expenses.

Based on a review of the Company's October 3, 2005 memo and the supporting documentation provided by UNS Gas, Staff concludes that the deferred GIS costs requested by UNS Gas are not an appropriate rate base item, do not qualify as a "regulatory asset," were not pre-approved for deferral by the Commission, are non-recurring costs that should have largely been expensed by the Company in periods prior to the 2005 test year, and therefore are not appropriate to include in test year rate base.

Q. Does Staff have a related adjustment to UNS Gas's expenses?

A. Yes. UNS Gas had proposed to amortize the deferred GIS cost over three years. As explained in more detail in a subsequent section of my testimony, Staff adjustment C-5 removes that amortization expense.

<u>B-3, Cash Working Capital</u>

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of three separate subcomponents. The subcomponents are: (1) a negative cash working capital balance of $3.281 million based on a lead/lag study; (2) a thirteen-month average materials and supplies balance of $2.040 million; and (3) a thirteen-month average prepayments balance of $195,942. As shown on Company Schedule B-5, UNS Gas' rate base reflects a request for working capital of negative $1.045 million. I will address the Company's cash working capital request, along with the lead/lag study UNS Gas provided as support for that request.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does UNS Gas have a positive or negative cash working capital requirement?

A. UNS Gas has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did UNS Gas present a lead/lag study in support of its cash working capital requirement?

A. Yes, UNS Gas performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has UNS Gas made any revisions to the cash working capital calculation included in its filing?

A. Yes. According to the response to data request STF 5.76[4], there was an error in the cash working capital schedule in the Company's filing. Specifically, UNS Gas's response to STF 5.76 indicated that at Company Schedule B-5, line 19, "Revenue Taxes and Assessments" the amount should be $11,966,406 as opposed to $18,788,535. This Company-identified correction would change the balance of negative cash working capital from $3,280,866 to $2,586,909, increasing rate base by $693,957.

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[4] A copy of this response is provided in Attachment RCS-5.

A related impact on income taxes also affects the amount of cash working capital allowance that is deducted from rate base.

Q. Are you recommending any revisions to UNS Gas' cash working capital request?

A. Yes. As mentioned above, I have reflected UNS Gas's corrected cost amounts in my cash working capital calculation. I have also reflected the impact of Staff's adjustments to operating expenses, impacts on gas costs related to Staff's sales adjustments, and impacts on revenue based taxes. I have also synchronized the calculation with cash working capital with Staff's recommended revenue increase.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-3, UNS Gas' filed cash working capital request should be increased by approximately $771,000. UNS Gas's proposed cash working capital of negative $3.281 million should be increased to negative $2.510 million.

<u>**B-4, Accumulated Deferred Income Tax**</u>

Q. Please explain the adjustment to Accumulated Deferred Income Taxes ("ADIT").

A. This adjustment is shown on Schedule B-4, and increases rate base by $195,336 for the impact of the following:

1) removal of the ADIT related to the GIS deferral that UNS Gas added to rate base that was removed by Staff[5];

2) removal of the ADIT related to the Supplemental Executive Retirement Plan ("SERP")[6]; and

3) removal of 50 percent of the ADIT related to incentive compensation[7].

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[5] See Staff Adjustment B-2, discussed above.
[6] Also see Staff Adjustment C-6 that has removed the expense related to SERP.
[7] Staff adjustment C-6 allocates the cost of incentive compensation 50/50 between shareholders and ratepayers.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C, page 1, summarizes Staff's recommended net operating income. Schedule C.1, present Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNS Gas's proposed adjusted test year net operating income is $8.429 million, whereas Staff's recommended adjusted net operating income is $9.664 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1, Revenue Annualization

Q. Please explain Staff Adjustment C-1.

A. This adjustment presents Staff's revenue annualization. UNS Gas included a revenue annualization with its filing. The revenue annualization adjusts revenues to reflect the growth in customers that occurred throughout the test year. The customer level is annualized to year-end. In Staff's calculation December 2005 customers were used. The difference between actual December 2005 customers, by rate class, and the number of customers in each of the other months of the test year was identified. The change in customers to an annualized year-end level was then multiplied by the customer charge and margin amounts applicable to that rate class. In this adjustment, Staff used the same customer charge and margin amounts used by UNS Gas. As shown on Schedule C-1, Staff's revenue annualization adjustment resulted in $102,433 more gas revenue (excluding purchased gas) than did the revenue annualization proposed by UNS Gas.

C-2, Weather Normalization

Q. Please explain the adjustment for weather normalization.

A. This adjustment increases retail revenue by $1,962. Staff's adjustment varies from the weather normalization adjustment proposed by UNS Gas because the weighted average number of customers, in Staff's annualization, exceeded the corresponding level reflected in UNS Gas' corresponding annualization. Both the Staff and the UNS Gas weather normalization adjustments reflect an increase to revenue because the test year was warmer than normal. The details of Staff's adjustment are shown on Schedule C-2.

C-3, Bad Debt Expense

Q. Please explain the adjustment for bad debt expense.

A. This adjustment increases bad debt expense by $1,263. It is impacted by the higher annualized and normalized revenue levels derived by Staff in Adjustments C-1 and C-2, as well as higher total gas costs associated with the higher annualized gas sales volumes.

Q. How were uncollectibles related to the Company's collection of gas costs reflected in Staff's calculation?

A. Uncollectibles related to PGA revenue and to the gas cost recovered in base rates have traditionally been an operating expense for purposes of determining the utility's base rate revenue requirement. Under the Company's and Staff's proposals, UNS Gas would recover its gas costs fully through the PGA. For purposes of Staff's revenue requirement calculation, I have included gas cost-related uncollectibles in the determination of operating expenses.

Q. Do you agree with the Company's derivation of the uncollectibles factor?

A. Yes. Both Staff's and the Company's pro forma adjustment for bad debt expense use the two-year average uncollectibles factor calculated by the Company of 0.51052%. This same uncollectibles factor is also used in the gross revenue conversion factor shown on Schedule A-1.

C-4, Remove Depreciation and Property Taxes for CWIP

Q. Please explain Staff Adjustment C-4.

A. This adjustment removes the pro forma amounts calculated by UNS Gas for depreciation and property taxes related to the Company's proposal to include CWIP in rate base. As explained above[8], Staff disagrees with that Company proposal to include CWIP in rate base. Accordingly, Staff has also removed the pro forma depreciation and property tax expense adjustments proposed by UNS Gas. As shown on Schedule C-4, this reduces the Company's proposed expenses by $363,150.

C-5, Remove Amortization of Deferred GIS Cost

Q. Please explain Staff Adjustment C-5.

A. This adjustment removes the Company's proposed amortization of $299,023. As explained above in conjunction with Staff Adjustment B-2, during 2003-2005, UNS undertook a project to locate and assign global positioning system (GPS) information to its existing service lines in order to update the UNS Gas GIS. Part of the basis for this request by the Company is that the project has benefit to future periods. However, these expenses largely were incurred in prior periods and are nonrecurring. Without seeking Commission pre-approval, UNS Gas is now requesting deferral treatment for costs that should have been expensed in periods prior to the test year.

[8] See above discussion in conjunction with Staff Adjustment B-1.

Staff agrees with the portion of UNS Gas' adjustment that removes the non-recurring GIS costs from test year O&M expense.

Staff disagrees, however, with the Company's proposal to amortize such costs prospectively over a three-year period. UNS Gas is requesting a return of those prior-year costs plus related costs incurred during 2005, for the GIS project over a three-year period via its proposed amortization. Had it been expensed properly by UNS Gas in the appropriate periods, the vast majority of the GIS cost that UNS Gas deferred would have been expensed prior to the 2005 test year. As noted above, UNS Gas did not request Commission pre-approval of recovery, and could therefore not defer the costs as a regulatory asset. As explained above in conjunction with Staff Adjustment B-2, Staff disagrees with UNS Gas' proposed deferral treatment of such costs. Staff's rate base adjustment B-2 removed the deferred balance from rate base. Staff's Adjustment C-5 removes the related Company proposed amortization. This adjustment reduces UNS Gas' proposed amortization expense by $299,023.

C-6, Incentive Compensation and Supplemental Executive Retirement Program

Q. Please explain Staff Adjustment C-6.

A. This adjustment removes 50% of the expense related to the various incentive compensation programs in effect at UNS Gas and 100% of the expense for the Supplemental Executive Retirement Plan (SERP). In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Please discuss the UniSource Energy Corporation's Performance Enhancement Program.

A. As explained in the Company's supplemental response to data request STF 5.72, UNS Gas' non-union employees participate in UniSource Energy Corporation's Performance Enhancement Program ("PEP"). UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNS Gas. The structure of the PEP determines eligibility for certain bonus levels by measuring UES' performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout. The amount made available for bonuses pursuant to the PEP formula may range from 50 percent to 150 percent of the targeted payment level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's supplemental response to data request STF 11.5(c):

> "In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Gas financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in the response to STF 11.5 b, the 2005 primary financial goal was not met."

Q. Even though the primary financial goal under the PEP was not met in 2005, were incentive bonuses paid?

A. Yes, they were. As explained in UNS Gas' supplemental response to STF 11.5(b):

> "... the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Gas and Tucson Electric Power Company ("TEP"), was not met. The financial performance goal was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Aware was paid at approximately 42% of the target for each of the operating companies."

Q. Are you aware of any recent Commission decisions that reached similar conclusions regarding the appropriate ratemaking treatment of incentive compensation and SERP expense?

A. Yes. As an illustrative example, in Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted Staff's recommendation for an equal sharing of costs associated with that utility's management incentive plan compensation expense, and adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> "Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."

The adjustments to expense for the SERP and for each of UNS Gas' incentive compensation programs are shown on Schedule C-6. The adjustment reduces O&M expense by $262,223. A related impact on payroll tax expense reduces that by $5,202.

C-7, Emergency Bill Assistance Expense

Q. Please explain Staff Adjustment C-7.

A. This adjustment increases test year expense to be included in the base rate revenue requirement determination by $21,600 to provide for an increase requested by the Company for emergency bill assistance. UNS Gas had included this $21,600 in its request for increased funding for its low-income weatherization program. UNS Gas also requested that the low-income weatherization program be included in the Commission-approved Demand Side Management (DSM) programs. Staff agrees with increasing the Company's requested allowance for emergency bill assistance by the $21,600, but disagrees that this should be part of a DSM program or that this particular expense should be included in the separate DSM surcharge rate. Accordingly, Staff has reflected the $21,600 increase in emergency bill assistance as an increase to operating expenses, so this can be included in base rates, and has excluded this expense from DSM programs. As shown on Schedule C-7, this adjustment increases operating expense by $21,600. The testimony of Staff witness Julie McNeely-Kirwan contains further explanations of Staff's reasons for this treatment.

C-8, Remove Nonrecurring Severance Payment Expense

Q. Please explain Staff Adjustment C-8.

A. This adjustment removes a nonrecurring severance payment of $52,388 recorded in test year expense. An email dated January 11, 2005 in UNS Gas' workpapers explain this item as follows: "There is an employee at UNS Gas who was let go in July 2004 who had worked in cost center 581 in Flagstaff. As part of his severance agreement, it was agreed not to pay him his final severance until January 2005. The gross amount of the check being issued is $52,287.56. The check in January will be charged to task G510857." The Company's payroll adjustment recognized that this severance payment was nonrecurring, and did not apply a pro forma payroll increase to it. However, the Company also did not remove it from test year expense. It relates to a an employee whose severance occurred in 2004, is nonrecurring, and should be removed from test year expense as shown in Staff Adjustment C-8.

C-9, Overtime Payroll Expense

Q. Please explain Staff Adjustment C-9.

A. This adjustment reduces the amount of pro forma expense in the Company's payroll adjustment. In that adjustment, the Company attempted to normalize test year overtime based on a two-year average. As shown on Schedule C-9, Staff has recalculated the overtime normalization adjustment two ways, and each results in a pro reduction UNS Gas' proposed overtime expense, in contrast with the Company's calculation which resulted in an increase. Schedule C-9, page 1, shows Staff's calculation of normalized overtime expense which results in a reduction of $123,010 to the UNS Gas' proposed amount. Schedule C-9, page 2, shows an alternative calculation, which reduces UNS Gas' proposed amount by $138,876.

Q. Are there aspects to the Company's calculated overtime adjustment with which Staff agrees?

A. Yes. Staff agrees with the concept of using a two-year average of 2004 and 2005 overtime cost to produce a normalized overtime expense adjustment. As shown on Schedule C-9, pages 1 and 2, the amount of overtime charged to Operating and Maintenance (O&M) expense, and the total amount of overtime cost in 2005 was considerably higher than in 2004. The UNS Gas recorded amount of overtime charged to O&M expense, and the total amount of overtime cost in the 2005 test year is higher than the average for the two-year period 2004-2005.

Q. Please explain the calculations shown on Schedule C-9.

A. Schedule C-9, page 1, focuses on the overtime charged to O&M expense. UNS Gas' pro forma adjustment reflects an increase to O&M expense for overtime of $1.070 million. This is shown on line 1 of Schedule C-9. As shown on lines 4-6, overtime charged to O&M expense totaled $781,386 in 2004 and approximately $1 million in 2005. The average for the two-years was $890,915. The UNS Gas pro forma adjustment for regular payroll charged to O&M expense reflected an increase of approximately 6.3%, as shown on lines 7-9. Applying this same increase to the two-year average overtime expense amount of $890,915 produces an annualized adjusted overtime O&M expense of $947,123, as shown on lines 11-12. The difference between the $947,123 in Staff's calculation and the $1.070 million in UNS Gas' calculation is a reduction to the UNS Gas-proposed overtime expense of approximately $123,000.

Schedule C-9, page 2, focuses on the total increase to overtime cost, including pro forma overtime amounts charged to O&M expense and to non-O&M accounts. UNS Gas' pro forma adjustment reflects a total overtime cost of approximately $1.403 million. This is shown on line 1 of Schedule C-9, page 2. As shown on lines 6-9, overtime charged to O&M and non-O&M accounts totaled $992,499 in 2004 and approximately $1.3 million in 2005. The average for the two-years was $1.148 million. The UNS Gas pro forma adjustment for regular payroll reflected an increase of approximately 6.3%, as shown on lines 10-12. Applying this same increase to the two-year average total overtime cost of $1.148 million produces an annualized adjusted total overtime cost of $1.221 million, as shown on lines 13-15. As shown on lines 1-3, the difference between the $1.403 million in UNS Gas' calculation and the $1.221 million in Staff's calculation is a reduction total pro forma overtime cost of approximately $182,000. The portion of total overtime charged to O&M expenses is 76.3 percent, as shown on lines 16-18. The corresponding adjustment to O&M expense is $138,876, as shown on line 5.

Q. Which amount of overtime expense adjustment did you reflect in Staff's determination of net operating income?

A. I used the lower of the two adjustment amounts. The $123,010 reduction to the Company's proposed overtime expense was carried forward to Schedule C.1, page 2, in the column for Staff Adjustment C-9.

C-10, Payroll Tax Expense

Q. Please explain Staff Adjustment C-10.

A. This adjustment reduces test year payroll tax expense for the impact of Staff's other adjustments to payroll. As shown on Schedule C-10, pro forma payroll tax expense is reduced by $13,356.

C-11, Nonrecurring FERC Rate Case Legal Expense

Q. Please explain Staff Adjustment C-11.

A. During the 2005 test year, UNS Gas incurred substantial legal expenses related to settlement discussions in an El Paso Natural Gas rate case at the Federal Energy Regulatory Commission (FERC). That case has been settled. The expenses related to settlement negotiations in that case during May through December 2005 expensed by UNS Gas in the test year are therefore nonrecurring and should be removed. Those amounts were identified by the Company in response to data request STF 5.91 and amount to $311,051.

C-12, Property Tax Expense

Q. Please explain Staff Adjustment C-12.

A. This adjustment reflects the known statutory assessment ratio of 24 percent applicable for 2007. The Arizona State Legislature passed House Bill No. 2779 which set a new rate schedule for property tax assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The Company's calculation used a 24.5 percent assessment rate and thus fails to recognize the impact of this known tax change prospectively.

Q. How did Staff determine its recommended assessment rate?

A. The current assessment rate in 2007 is 24 percent. Staff concluded that since the Commission approved rates are expected to become effective in mid-2007, and the Company's anticipated rate case interval is three years, as evidenced by the Company's proposed normalization period for rate case expense, the property tax rate that will be in effect for 2007 of 24 percent is appropriate.

In terms of determining the recommended assessment rate, I also considered how Staff's recommendation in the current UNS Gas rate case compares with Staff's similar determination in the recent Southwest Gas rate case. This comparison is summarized in the following table:

Utility:	UNS Gas, Inc.	Southwest Gas Corp.
Docket:	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	December 31, 2005	August 31, 2004
New Rates Effective:	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years	3 to 4 years
Assessment Rate Used:	24 percent	24.5 percent
Corresponding Effective Year:	2007	2006

In the Southwest Gas case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending August 31, 2004. I believe the appropriateness of using the known 24 percent assessment rate in the current UNS Gas rate case is supported by the comparison in the above table.

Q. What is Staff's recommended property tax expense adjustment?

A. As shown on Schedule C-12, Staff's recommended adjustment reduces UNS Gas' proposed property tax expense by $80,290.

<u>C-13, Worker's Compensation Expense</u>

Q. Please explain Staff Adjustment C-13.

A. This adjustment reverses a UNS Gas' proposed adjustment to increase test year expense for using a cash basis, rather than an accrual accounting basis, for recognizing worker's compensation expenses for ratemaking purposes.

Q. How does the Company propose to treat worker's compensation expense for ratemaking purposes?

A. The Company proposes to increase test year recorded expenses by adjusting from the accrual basis that it uses for book accounting purposes to a cash basis for ratemaking.

Q. What is the basis for this Company proposal?

A. The Company apparently believes that a prior Commission ratemaking decision concerning Other Postemployment Benefits (OPEB) requires a similar treatment for worker's compensation expense. OPEBs cover post-retirement benefits, such as Company-paid retiree health care and life insurance. OPEBs are accounted for on an accrual basis, pursuant to FAS 106, for book purposes, but the Commission adjusted these to a pay-as-you-go method for ratemaking purposes in Decision No. 58664 (6/16/94) in a rate case involving Citizens Utilities Company, Arizona Gas Division. It is unclear from the information provided by UNS Gas how OPEB expenses have been treated for ratemaking purposes in subsequent cases.

Q. How was Worker's Compensation expense recorded on UNS Gas' books during the 2005 test year?

A. As explained in the Company's response to data request RUCO 6.09:

> "The Worker's Compensation expense is recorded under Statement of Financial Accounting Standards No. 112, Employer's Accounting for Postemployment Benefits ("FAS 112"). FAS 112 specifically states that post employment benefits are all types of benefits provided to former or inactive employees and worker's compensation is included as a post employment benefit."

Q. When was FAS 112 issued?

A. FAS 112 was issued by the Financial Accounting Standards Board ("FASB") in November 1992.

Q. When did FAS 112 first become required accounting?

A. FAS 112 was effective for fiscal years beginning after December 15, 1993. Basically, it has been part of required GAAP since 1994.

Q. Has UNS Gas proven that FAS 112 was not used for accounting or ratemaking purposes in Arizona since 1994?

A. No. The information provided by UNS Gas has not documented any Commission rulings requiring worker's compensation expense to be recorded on a cash basis for ratemaking purposes. Data request RUCO 6.06, for example, referenced UNS Gas' pro forma adjustment for worker's compensation expense and asked the Company to: "Please provide additional back-up information, which verifies the Commission's historical treatment of this expense is required to be recorded on a cash basis." The Company responded that: "UNS Gas does not have this additional back-up information."

Q. How does Staff propose to treat worker's compensation expense in the current case?

A. Staff proposes to treat the expense in accordance with the accrual accounting prescribed in FAS 112. There is no compelling reason to deviate from the generally accepted accounting for worker's compensation in the current UNS Gas rate case. The Company's proposed increase to worker's compensation expense of $34,234 is unjustified and should be rejected.

__**C-14, Membership and Industry Association Dues**__

Q. Please explain Staff's proposed adjustment for Membership and Industry Association Dues.

A. This adjustment reduces test year expense by $26,868, as shown on Schedule C-14. It removes 40 percent of UNS Gas' 2005 American Gas Association ("AGA") dues for

2005, which were $41,854. It also removes other discretionary membership and industry association dues which are not needed for the safe and reliable provision of gas utility service.

Q. Did UNS Gas' AGA dues increase substantially in 2005?

A. Yes. An Invoice provided by the Company in response to data request STF 16.1 indicated that 2004 AGA dues were $20,927 and 2005 dues were $41,854. The invoice indicates that the 2004 amount represents one-half of full dues and the 2005 amount represents the phase-in to full dues.

Q. How did you determine the 40 percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent National Association of Utility Regulatory Commissioners (NARUC) sponsored Audit Reports of the Expenditures of the American Gas Association. Copies of relevant pages from those audit reports are provided in Attachment RCS-3.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures[9]: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The

[9] This is the most recent NARUC-sponsored audit report on AGA expenditures currently available.

NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commission required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Attachment RCS-4, an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

> "In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake

Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment."

Q. What amount of membership dues expense has Staff removed from test year expense?

A. As shown on Schedule C-14, Staff has removed $26,868 in test year expense for membership dues.

<u>C-15, Fleet Fuel Expense</u>

Q. Please explain Staff Adjustment C-15.

A. This adjustment reduces the Company's proposed post-test year increase for vehicle fleet fuel expense. Staff's adjustment follows a similar format to the UNS Gas proposed adjustment for fleet fuel expense. Staff's adjustment allows for a pro forma fuel expense increase of $21,287 based on a cost of gasoline of $2.26 per gallon from a 3 Month Average Retail Price Chart as of January 17, 2007, at ArizonaGasPrices.com. UNS Gas' proposed adjustment is reduced by $52,439, as shown on Schedule C-15.

<u>C-16, Postage Expense</u>

Q. What adjustment has UNS Gas proposed for postage expense?

A. UNS Gas has proposed an adjustment to increase postage expense by $142,707. This is shown on in UNS Gas' filing, at Schedule C-2, page 4, line 5.

Q. Does Staff agree with that adjustment?

A. Not fully. Staff is in agreement that a postage increase has occurred and should be recognized for ratemaking purposes. To derive the annualized postage expense, Staff increased the test year recorded postage expense of $386,673 for the postage increase that became effective January 8, 2006 ($0.02 / $0.37) and for the increase in the number of customers from the test year average to year-end. As shown on Schedule C-16, Staff has calculated an adjustment for annualized postage expense of $414,285. This reduces UNS Gas' proposed amount of $529,380 by $115,095.

C-17, Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-17. This adjustment increases income tax expense by the amount shown on Schedule C-17 and decreases the Company' achieved operating income by a similar amount.

V. DEPRECIATION RATES

Q. Please discuss the new depreciation rates that UNS Gas has proposed.

A. The development of new depreciation rates is addressed in the testimony of UNS Gas witness Ronald White, who sponsors the Company's 2006 depreciation rate study. The table presented at page 10 of Dr. White's testimony summarizes the overall changes. The depreciation rates proposed by primary account are equivalent to a composite rate of 2.73 percent. This is a reduction of 0.21 percentage points in comparison to the current composite rate of 2.94 percent. On December 31, 2005 plant investment, the difference between the current and proposed new depreciation rates produces a decrease in annualized depreciation expense for the gas utility of $610,980. This is shown on Statement B, at numbered page 18 of Dr. White's Attachment REW-2.

Q. Please briefly describe the information you reviewed concerning UNS Gas' proposed depreciation rates.

A. The information I reviewed included the Commission's rules regarding depreciation, testimony and exhibits from the prior rate case, UNS Gas' application and testimony in the current case, UNS Gas' responses to data requests of Staff and other parties, Excel files supporting UNS Gas witness Ronald White's derivation of UNS Gas' depreciation rates, information provided to me by Staff, and other publicly available information.

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. A copy of these rules are presented, for ease of reference, in Attachment RCS-6. The current version of the rules appear to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discuss SFAS No. 143 in more detail subsequently in my testimony.

Q. Did UNS Gas file a new depreciation study in the current rate case?

A. Yes. Exhibit REW-2 attached to Dr. White's testimony is the 2006 Depreciation Rate Study for UNS Gas, Inc.

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by UNS Gas are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibits, his Attachment REW-2.

The Company's proposed rates were developed using a depreciation system composed of the straight-line method, broad group procedure and remaining life technique.

Q. What impact do the new depreciation rates proposed by UNS Gas have?

A. As summarized on page 10 of Dr. White's testimony, based on December 31, 2005 plant investment, the new depreciation rates proposed by UNS Gas decrease depreciation expense by $610,980 (from $8,542,838 at present rates to $7,931,868 at the Company's proposed rates).

On a composite basis[10], the Company's proposed new rates produce an decrease of 0.21 percentage points, from the current composite rate of 2.94% to a composite at new rates of 2.73%.

Q. Before discussing specific issues associated with UNS Gas' proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

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[10] UNS Gas does not apply its depreciation rates on a composite basis; this information is for comparative purposes only.

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> "the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; of if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [11]

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant

[11] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

account. An annual addition is the original cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a <u>non-cash</u> expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

Account	Description	Amount Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	

various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please illustrate how depreciation rates are developed.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10% depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. What happens at the end of an asset's life under this scenario?

A All things equal, at the end of 10 years, the plant balance will be 100% (or $1 million), and the accumulated depreciation balance will also be 100% (also $1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised by a Staff witness (Mr. Majoros) as a major issue affecting utility depreciation rates in a previous APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55% value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole-life depreciation rate from 10% to 15.5%, i.e., by 55%. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143. (SFAS 143) I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 155%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of life under this scenario?

A. The plant balance will be 100% but the sum of the accumulated depreciation balance and the regulatory liability account will be 155%. Consequently, unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. Where there is no legal requirement to incur cost of removal, UNS Gas has no current legal liability to spend money for estimated future cost of removal, the Commission rules at R14-2-102(B)(3) require that: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. **Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?**

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55% net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. **What would happen if either of these fundamental parameters were to change?**

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than the whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles (GAAP), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 (FAS 143). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., UNS Gas) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does not have such legal obligations, the future cost of removal will not be capitalized as part of the asset cost and will not be included in depreciation expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists), will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q. How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under Generally Accepted Accounting Principles ("GAAP"), electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non- AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long -lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as “non-legal retirement obligations.” Past and future "non- legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the transparency resulting from the “separation principle” for non-legal AROs that was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631 explains FERC’s new requirements for non-legal AROs:

> “Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals.”

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, at paragraph 39 of the order, FERC states:

> "Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. As indicated at paragraph 64 of the Order, FERC declined to make such calls on a policy basis. Rather, FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis.

Q. Does FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. At paragraph 65 of the Order, FERC states that:

> "... this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of

> detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates."

Additionally, footnote 45 states:

> "When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS 143 recognizes those distinctions. On a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. Has UNS Gas implemented SFAS 143?

A. Yes. The Company has implemented SFAS 143. Consistent with adopting this accounting principle for financial reporting purposes, UNS Gas reclassified prior year removal costs of approximately $3 million previously included in accumulated depreciation to the liability for asset retirements and removals in its Balance Sheets.

When initially adopting SFAS 143, companies such as UNS Gas, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

As described in the notes to the consolidated financial statements of the UniSource Energy, TEP and Subsidiaries in their 2005 Securities and Exchange Commission ("SEC") Form 10-K, under the heading "Regulatory Assets and Liabilities":

> "… UNS Gas has recorded regulatory liabilities for the Net Cost of Removal for Interim Retirements from its distribution and general plant of $3 million as of December 31, 2005 and $2 million as of December 31, 2004."

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of UNS Gas' past depreciation rates?

A. Essentially, yes. Similar to most utilities, UNS Gas' past depreciation rates have included negative net salvage. This has resulted in UNS Gas pre-collecting from ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful lives. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of UNS Gas' depreciation rates. The inclusion of negative future net salvage ratios in UNS Gas' proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do UNS Gas' proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, UNS Gas' proposed depreciation rates include estimated future removal costs, including estimated future inflation. UNS Gas has done this by including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets.

Q. Where does UNS Gas develop its estimated future cost of removal that are included in its proposed depreciation rates?

A. These are developed in Mr. White's Attachment REW-2, on Statement D (average net salvage), Statement E (present and proposed parameters) of those attachments.

Q. Did you request UNS Gas to provide its <u>actual</u> cost of removal and net salvage information by plant account?

A. Yes. This was requested in data request STF-5.28 for years 2000 through 2005.

Q. Did UNS Gas provide that requested information plant account?

A. UNS Gas provided some but not all of the requested information. In response to STF 5.28, the Company stated that: "The assets of UNS Gas were acquired from Citizens Communications Company ("Citizens") on August 11, 2003. Cost of removal and salvage data from periods prior to that date are not available." Data that UNS Gas did provide shows that there was no cost of removal in 2003 or 2004, cost of removal of totaling $3,535 for mains in 2005 and salvage (proceeds from the sale of transportation equipment) of $213,065 in 2005. In other words, in 2005, UNS Gas had net salvage of $209,530.

Q. Have you made a comparison of how much UNS Gas' proposed depreciation rates would collect annually for estimated future cost of removal with the Company's recent actual cost of removal?

A. No. During the course of my analysis, I started to make such a comparison, but concluded that it was not necessary for purposes of this case because the Commission's rules at R14-2-102 require net salvage to be included in the development of the utility's depreciation rates. Since I am not recommending an adjustment to reflect an alternative treatment of cost of removal in this case, the comparative calculation related to quantifying such an adjustment was not pursued as it would have been if an adjustment to the Company's approach was being recommended.

Q. Has UNS Gas' approach to including net salvage in depreciation rates been widely used in the utility industry?

A. Yes. Many regulated utilities have used this approach. It is even addressed in the NARUC's 1996 Public Utilities Depreciation Practices Manual as a recommended approach. On the other hand, the same NARUC Manual at page 157 also states:

"Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred."

Q. In your opinion, is there a reasonable alternative to the approach used by UNS Gas?

A. Yes. Instead of incorporating estimated future cost of removal along with estimated future inflation into depreciation rates, providing a normalized level of removal cost as a current-period expense is a reasonable alternative for ratemaking purposes, in my opinion.

Q. Does the NARUC Manual indicate that some utility commissions are using this alternative approach?

A. Yes. The NARUC Manual at page 158 states that:

It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current period accounting for gross salvage and, particularly, cost of removal.

Q. Could UNS Gas' approach result in accumulated depreciation exceeding the original cost of plant in service?

A. Yes. One of the mechanical problems with UNS Gas' approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rates proposed by UNS Gas for distribution plant include estimated future cost of removal, and therefore produce higher depreciation rates than are necessary to fully depreciate the original cost of the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. Referring back to the hypothetical illustration that I presented earlier, with a 55% negative net salvage assumption, at the end of the 10-year assumed useful life, the utility has recorded $1.55 million in depreciation on a depreciable asset of $1 million. During the plant's depreciable life, the utility had no asset retirement obligation, but it would have collected an extra $550,000.

Q. How should the allowance for cost of removal be calculated?

A. Because the Commission's rules at R14-2-102 in their current form clearly require the inclusion of net salvage in the development of the utility's depreciation rates, and this is what UNS Gas has done, I am not in this proceeding recommending an alternative. Were it not for those rules, I believe there is substantial merit in the alternative recommended by the witness for Staff in the prior APS rate case cited above, which would provide for a normalized allowance for cost of removal based on the average of the most recent five years worth of actual net salvage activity. Essentially, the cost of removal is treated just as any other normalized operating expense.

Q. Are you aware of whether other regulatory commissions use that alternative approach for utility recovery of cost of removal?

A. Yes. A five-year average net salvage allowance approach has been used for many years by the Pennsylvania Public Utility Commission. In recent years, some other state regulatory commissions have used similar approaches that exclude estimated future cost of removal from the development of depreciation rates, and provide an allowance for the cost of removal based on an average of a utility's actual incurred cost.

Q. What are the advantages of that approach?

A. The five-year rolling average for recovery of cost of removal provides a reasonable method for addressing this controversial aspect of depreciation. UNS Gas' proposed development of depreciation rates essentially treats estimated future costs of removal (including estimated future inflation) as a current period expense, even when there is no current legal obligation to incur such cost. In contrast with UNS Gas' approach, a normalized expense allowance approach better conforms with the generally accepted accounting principles articulated in SFAS 143 by not treating estimated inflated future removal costs as if they were a current obligation and a current expense. Additional advantages offered by the normalized expense allowance approach include that it is simple, straight-forward and easy to implement, provides an opportunity for the Company to recover a normalized allowance for cost of removal based on recent actual cost, and avoids charging current customers for estimated future inflation. However, the Commission's rules at R14-2-102 in their present state would appear to preclude this alternative for purposes of this case.

Rule R14-2-102 is a rule of general applicability to electric utilities in the state of Arizona. Because I believe there is no compelling reason to treat cost of removal (where there is no current obligation to incur such cost) differently from other normalized operating expenses, I recommend that the Commission consider amending Rule R14-2-102 to allow treatment of cost of removal in the manner recommended by Staff's consultant in the prior APS rate case.

Q. Should the depreciation rates proposed by UNS Gas be adopted for use in this case?

A. Yes. The depreciation rates proposed by UNS Gas presented in Dr. White's Attachment REW-2 should be adopted for use in this case. The depreciation rates proposed by UNS Gas were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Dr. White's Attachment REW-2 and other information indicates that those new rates proposed by UNS Gas are consistent with industry accepted depreciation practices. As noted above in my testimony, the net change in percentage terms resulting from UNS Gas' proposed new depreciation rates in composite terms is fairly small, a decrease of 0.21 percentage points for UNS Gas plant.

Q. Do you have any other recommendations concerning the depreciation rates proposed by UNS Gas?

A. Yes. Each of the new depreciation rates proposed by UNS Gas should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

VI. CHANGES TO RULES AND REGULATIONS

Q. What revisions to rules and regulations has UNS Gas proposed that you are addressing?

A. I am addressing the revisions to the rules and regulations described in the direct testimony of UNS Gas witness Gary Smith at pages 19-20, specifically:

- Section 6.B.2.b, gas service line reimbursement.
- Section 10.C, billing terms.
- Section 10.j, electronic billing.
- Section 11.E, timing of terminations with notice
- Section 7, extension of lines

Q. What has UNS Gas proposed for the amount that the customer would reimburse the Company for the gas service line on the customer's property?

A. UNS Gas proposes to change Section 6.B.2.b such that the amount the customer would reimburse the Company for the gas service line on the customer's property was increased from $8.00 per foot to $16.00 per foot to reflect current costs. Other changes provide that the customer is now responsible for locating facilities on private property and removing landscaping prior to installation or is to be subject to applicable charges. For customers who provide the trench for the service line on their own property, the rate at which the customer will reimburse the Company has been increased to $12.00 per foot for the excess footage.

Q. Have you reviewed the cost support provided by UNS Gas in support of its proposed changes for service lines and establishments charges?

A. Yes. I have reviewed the information provided by UNS Gas in response to Staff set 13, including Staff data requests 13.2, 13.6 and 13.7. I conclude that reasonable cost support exists for the increased gas service line reimbursement rates proposed by UNS Gas. Increasing such reimbursement rates, as proposed by the Company, should also help alleviate the initial cost impacts associated with customer growth, by having the customer reimburse UNS Gas based on a reimbursement rate that is more closely aligned with the utility's cost. This should help alleviate a concern that the robust customer growth UNS Gas is experiencing may be a factor in driving up the cost of service to existing customers.

Q. Please discuss the changes UNS Gas is proposing for Section 7, Extension of Lines.

A. The Company has attached a redlined version of Section 7 (as well as the other sections of its proposed changes to rules and regulations) to Gary Smith's direct testimony in Exhibit GAS-2. Page 20 of his direct testimony states that these changes are to update the UNS Gas tariff to reflect current market conditions and make them consistent with the Company's policy of asking developers to pay a fair cost for infrastructure installed to serve their facilities. The changes to Section 7 proposed by UNS Gas are quite extensive and include, but are not limited to these:

- 7.A.1, has added: "If downstream usage changes or is altered by the Customer, the Customer may be responsible for costs to upgrade or enlarge the service line to accommodate additional capacity requirements."
- 7.B, changing the General Policy to read: "All service and main line extensions agreements are made on the basis of economic feasibility." A provision that the Company would extend thirty (30) feet of main for each applicant who connects a functioning water heater or furnace within four (4) months of the completion of the main is being deleted.
- 7.B.4.b has been changed to read: "If the [Incremental Contribution Study] ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce their cost of service line installation."

Previously, this provision had included a statement that: "All applicants will pay for the entire length of their service lines on their property," which is being deleted in UNS Gas' proposed changes.

- 7.B.4.f is being added, to provide as follows: "For the purposes of this rule, 'economic feasibility' means that the estimated incremental revenues derived from serving the Applicant, less the incremental gas cost to serve the Applicant, meets the estimated costs of serving the Applicant, including meeting capital costs as determined by the weighted average cost of capital authorized by the ACC in the Company's most recent general rate case. An extension will not be considered economically feasible if the Applicant does not install a functioning water heating and furnace within four (4) months of the completion of the main."

- 7.B.5, which addresses the method of refund is being substantially changed.

- 7.C.1.b, concerning Advances, is being changed to provide as follows: "The Company may require a subdivider, builder or developer to provide trenching for service lines and/or distribution mains and may also require the subdivider, builder or developer to provide bedding & shading material to Company specifications."

- 7.D.1, concerning Postponement of Advance, is reworded to provide in part as follows: "When advances are postponed, the Applicant may be required to furnish to the Company, a Company-approved surety, to assure payment of any postponed amounts throughout the term of the facilities extension agreement up until the end of the postponement period."

- 7.D.5, a revision proposed by UNS Gas removes the definition of "Branch Services" from that provision.

- 7.D.6.c, is added to provide that: "The estimated cost of main extension and any resulting Main Extension Agreement is valid for ninety (90) days from the date of

Company issue. Any signed agreement with appropriate payment where construction does not commence within ninety (90) days may be subject to review, recalculation and adjustment of advance requirements."

- 7.D.16, Taxes Associated with Nonrefundable Contributions and Advances, contains an extensive addition, which appears to substantially clarify these provisions.

Q. What is your assessment of the fairly extensive changes proposed by UNS Gas to Section 7 regarding Extension of Lines?

A. While one could quibble about whether some of the wording changes proposed by the Company are really an improvement over the existing provisions, overall the Company-proposed changes appear to be appropriate and consistent with a policy of asking developers to pay a fair cost for infrastructure installed to serve their facilities.

Q. Why is UNS Gas proposing to change the provisions of its tariff at Section 10.C, Billing Terms?

A. As explained in the Company's response to STF 13.8, the current terms in the Rules and Regulations section were approved by the Commission in Decision No. 66028 with the acquisition of the utility operation from Citizens. The revisions proposed by UNS Gas are intended to align the UNS Gas' "Billing Terms" with those of TEP and UNS Electric (both UniSource Energy Companies), thereby minimizing confusion among UNS Gas and UNS Electric customers who are often the same individuals. As explained further in the response to STF 13.9(c):

> "TEP's current due date and time periods for late penalty charges are the same as those proposed by UNS Gas. Proposed revisions to UNS Electric's Rules and

Regulations were filed on December 15, 2006. The proposed UNS Electric revisions match those of UNS Gas and TEP."

Q. Does Staff agree with this proposal by UNS Gas?

A. Yes. Minimizing customer confusion by standardizing billing terms for the UniSource Energy Companies is an appropriate objective. The changes proposed by UNS Gas also appear to be consistent with the specifications of the Arizona Administration Cost ("AAC") at R14-2-310(c). Consequently, Staff agrees with the UNS Gas-proposed changes to Section 10.C. In order that these changes not present a hardship on UNS Gas customers, there should be a six month waiver in the late payment penalty charge. The Company has proposed to reduce the number of days, from 15 to 10, as the period a customer may avoid a late payment penalty. For the first 6 months, the penalty should be waived from day 10. After the initial 6 months, the Company should be able to charge the penalty after day 10. This temporary six-month transition period should help alleviate any hardship on customers from this change in billing terms.

Q. What is the basis for UNS Gas' proposed changes to Section 10.J, Electronic Billing?

A. As explained in the Company's response to STF 13.10(a):

> "UNS Gas' proposed provision for electronic billing was based on TEP's electronic billing program. The new electronic billing program will have the same capabilities once UNS Gas converts to its new customer information system. The Company did not make comparisons with other Arizona utilities concerning electronic billing."

Q. Have UNS Gas' utility affiliates already begun to offer e-bill programs?

A. Yes. As explained in the Company's response to STF 13.10(b):

> "TEP e-bill began in May of 2003. UNS Electric launched e-bill in January 2006. For both Companies, customers can sign up for e-bill via telephone or the company web site. Customer are notified via email that their bill is ready to view."

As indicated in the response to STF 13.10(c), the customer response to e-bill appears to be positive, with a growing number of TEP and UNS Electric customers signing up and using it.

Q. Does UNS Gas anticipate any savings (e.g., postage, bill printing, etc.) from electronic billing?

A. Yes. As indicated in the response to STF 13.10(d), the Company estimates that during the test year it realized savings in postage, bill stock, mailing envelopes and remittance envelopes of approximately $4,000.

Q. Does Staff support UNS Gas' proposal to offer its customers an e-bill option?

A. Yes.

Q. Please discuss UNS Gas' proposal to revise Section 11.E.

A. This proposal is presented in UNS Gas' witness Gary Smith's testimony at page 20. The Company proposes to shorten the advance notice provision from ten days to five days. As explained in the response to STF 13.11(d) and (g), the five days provision is based on AAC R14-2-311(E)(1), and TEP and UNS Electric currently match the AAC's five day advance notice provision. As explained in response to STAF 13.11(f) the current ten days and the UNS Gas-proposed five days are both stated in terms of calendar days. Information provided by the Company in response to STF 13.11(b) and (c) lists the number of Suspension of Gas Service Notices mailed to customers and the number of terminations UNS Gas conducted, respectively, for 2004 through 2006, and for August 11 through December 31, 2003. The 2004 through 2006 data is impacted by moratoriums on mailing notices and disconnects that were effective for portions of those years.

Q. Does Staff agree with UNS Gas' proposed revision to Section 11.E?

A. In general, Staff supports the standardization of tariff provisions for rules and regulations for the UniSource Energy Companies, including UNS Gas. Staff does not object to the UNS Gas' proposed revision to Section 11.E; however, Staff is concerned that the shortening of notice time could present a hardship to customers. Therefore, Staff recommends that during the first six months after the notification provisions are approved, the Company allow affected customers the current ten calendar days to respond to a termination of service notice before actually disconnecting the customers. After six months, the new terms in Section 11.E would be enforceable as stated.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Washington, Washington, D.C., Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

Attachment RCS-2

Staff Accounting Schedules

Accompanying the Direct Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Adjustments to Rate Base	1
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Remove Construction Work in Progress	1
B-2	Remove GIS Deferral	1
B-3	Cash Working Capital - Lead/Lag Study	1
B-4	Accumulated Deferred Income Taxes	1
	Net Operating Income Adjustments	
C-1	Revenue Annualization	1
C-2	Weather Normalization	1
C-3	Adjustment to Bad Debt Expense	1
C-4	Remove Depreciation & Property Taxes for CWIP	1
C-5	Remove Amortization of Deferred GIS Cost	1
C-6	Incentive Compensation and SERP	1
C-7	Emergency Bill Assistance Expense	1
C-8	Remove Nonrecurring Severance Payment Expense	1
C-9	Overtime Payroll Expense	2
C-10	Payroll Tax Expense	1
C-11	Nonrecurring FERC Rate Case Legal Expense	1
C-12	Property Tax Expense	1
C-13	Worker's Compensation Expense	1
C-14	Membership and Industry Association Dues	1
C-15	Fleet Fuel Expense	1
C-16	Postage Expense	1
C-17	Interest Synchronization	1
	Total Pages	31

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule A

			UNS Proposed		Staff Proposed	
Line No.	Description	Reference	Original Cost	Fair Value	Original Cost	Fair Value
			(A)	(B)	(C)	(D)
1	Adjusted Rate Base	Sch. B	$ 161,661,361	$ 191,177,715	$ 154,541,358	$ 184,057,711
2	Rate of Return	Sch. D	8.80%	7.44%	8.12%	6.82%
3	Operating Income Required		$ 14,223,179	$ 14,223,179	$ 12,548,758	$ 12,548,758
4	Net Operating Income Available	Sch. C	$ 8,428,981	$ 8,428,981	$ 9,664,497	$ 9,664,497
5	Operating Income Excess/Deficiency		$ 5,794,198	$ 5,794,198	$ 2,884,261	$ 2,884,261
6	Gross Revenue Conversion Factor	Sch. A-1	1.6649	1.6649	1.636969	1.636969
7	Overall Revenue Requirement		$ 9,646,901	$ 9,646,901	$ 4,721,446	$ 4,721,446

Notes and Source

Cols. A & B: UNS Gas, Inc. filing, Schedule A-1

UNS Gas, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule A-1

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.51%	0.51052%
3	Taxable Income as a Percent	99.49%	99.48948%
4	Less: Federal and State Income Taxes	39.43%	38.40095%
5	Change in Net Operating Income	60.06%	61.08853%
6	Gross Revenue Conversion Factor	1.6649	1.636969

Notes and Source
Col.A: UNS Gas Inc. Filing, Schedule C-3
Col.B: Response to STF 5.76, item 6

Components of Revenue Requirement Increase

	Amount	Percent
Net Income	$ 2,884,262	61.09%
Federal and State Income Taxes	$ 1,813,080	38.40%
Uncollectibles	$ 24,104	0.51%
Total Revenue Increase	$ 4,721,446	100.00%

UNS Gas, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended December 31, 2005

Line No.	Description	Original Cost: As Adjusted by UNS (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)	RCND: As Adjusted by UNS (D)	RCND: Staff Adjustments (E)	RCND: As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 279,169,694	$ (7,189,231)	$ 271,980,463	$ 374,243,421	$ (7,189,231)	$ 367,054,190
2	Less: Accumulated Depreciation	$ (72,006,708)	$ -	$ (72,006,708)	$ (97,114,865)	$ -	$ (97,114,865)
3	Net Utility Plant in Service	$ 207,162,986	$ (7,189,231)	$ 199,973,755	$ 277,128,556	$ (7,189,231)	$ 269,939,325
4	Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -	$ -	$ -	$ -	$ -	$ -
6	Net Southern Union Acquisition Premium	$ -		$ -	$ -	$ -	$ -
7	Citizens Acquisition Discount	$ (30,709,738)	$ -	$ (30,709,738)	$ (41,822,562)	$ -	$ (41,822,562)
8	Less: Accum. Amort. - Citizens Acq. Discount	$ (1,876,981)	$ -	$ (1,876,981)	$ (2,560,308)	$ -	$ (2,560,308)
9	Net Citizens Acquisition Discount	$ (28,832,757)	$ -	$ (28,832,757)	$ (39,262,254)	$ -	$ (39,262,254)
10	Total Net Utility Plant	$ 178,330,229	$ (7,189,231)	$ 171,140,998	$ 237,866,302	$ (7,189,231)	$ 230,677,071
11	Customer Advances for Construction	$ (7,283,595)	$ -	$ (7,283,595)	$ (7,786,962)	$ -	$ (7,786,962)
							$ -
12	Customer Deposits	$ (3,040,484)	$ -	$ (3,040,484)	$ (3,040,484)	$ -	$ (3,040,484)
							$ -
13	Accumulated Deferred Income Taxes	$ (6,484,809)	$ 195,336	$ (6,289,473)	$ (6,484,809)	$ 195,336	$ (6,289,473)
14	Total Deductions	$ (16,808,888)	$ 195,336	$ (16,613,552)	$ (17,312,255)	$ 195,336	$ (17,116,919)
15	Allowance for Working Capital	$ (1,045,146)	$ 770,960	$ (274,186)	$ (1,045,146)	$ 770,960	$ (274,186)
							$ -
16	Regulatory Assets	$ 1,204,887	$ (897,068)	$ 307,819	$ 1,204,887	$ (897,068)	$ 307,819
							$ -
17	Regulatory Liabilities	$ (19,721)	$ -	$ (19,721)	$ (19,721)	$ -	$ (19,721)
18	Total Rate Base	$ 161,661,361	$ (7,120,003)	$ 154,541,358	$ 220,694,067	$ (7,120,003)	$ 213,574,064

Notes and Source
Cols. A and D: UNS Gas Inc. filing, Schedule B-1

Fair Value Calculation (Per Company)

Original Cost	$ 161,661,361	
RCND	$ 220,694,067	
Total	$ 382,355,428	
Average (Fair Value)	$ 191,177,715	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 154,541,358	
RCND	$ 213,574,064	
Total	$ 368,115,422	
Average (Fair Value)	$ 184,057,711	See Sch. A

UNS Gas, Inc.
Summary of Rate Base Adjustments

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B.1

Line No.	Description	Staff Adjustments	CWIP B-1	GIS Deferral B-2	Cash Working Capital B-3	ADIT B-4	B-5	B-6
1	Gross Utility Plant in Service	$ (7,189,231)	$ (7,189,231)					
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (7,189,231)	$ (7,189,231)	$ -	$ -	$ -	$ -	$ -
4	Southern Union Acquisition Premium	$ -						
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -						
6	Net Southern Union Acquisition Premium	$ -						
7	Citizens Acquisition Discount	$ -						
8	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
9	Net Citizens Acquisition Discount	$ -						
10	Total Net Utility Plant	$ (7,189,231)	$ (7,189,231)	$ -	$ -	$ -	$ -	$ -
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Accumulated Deferred Income Taxes	$ 195,336				$ 195,336		
14	Total Deductions	$ 195,336	$ -	$ -	$ -	$ 195,336	$ -	$ -
15	Allowance for Working Capital	$ 770,960			$ 770,960			
16	Regulatory Assets	$ (897,068)		$ (897,068)				
17	Regulatory Liabilities	$ -						
18	Total Rate Base	$ (7,120,003)	$ (7,189,231)	$ (897,068)	$ 770,960	$ 195,336	$ -	$ -

UNS Gas, Inc.
Adjusted Net Operating Income

Test Year Ended December 31, 2005

Line No.	Description	As Adjusted by UNS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Gas Retail Revenues	$ 45,689,225	$ 104,395	$ 45,793,620
2	Other Operating Revenues	$ 1,480,303	$ -	$ 1,480,303
3	Total Operating Revenues	$ 47,169,528	$ 104,395	$ 47,273,923
	Operating Expenses			
4	Purchased Gas	$ 355,528	$ -	$ 355,528
5	Other O&M Expenses	$ 24,459,035	$ (954,445)	$ 23,504,590
6	Depreciation & Amortization	$ 7,220,392	$ (495,289)	$ 6,725,103
7	Taxes Other Than Income Taxes	$ 4,730,094	$ (265,732)	$ 4,464,363
8	Income Taxes	$ 1,975,498	$ 584,344	$ 2,559,842
9	Total Operating Expenses	$ 38,740,547	$ (1,131,121)	$ 37,609,426
10	Net Operating Income	$ 8,428,981	$ 1,235,516	$ 9,664,497

Notes and Source

Col. A: UNS Gas Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Stafff Adjustments	Revenue Annualization	Weather Normalization	Adjustment to Bad Debt Expense	Remove Depreciation & Property Taxes for CWIP	Remove Amortization of Deferred GIS Cost
			C-1	C-2	C-3	C-4	C-5
	Operating Revenues						
1	Gas Retail Revenues	$ 104,395	$ 102,433	$ 1,962			
2	Other Operating Revenues	$ -					
3	Total Operating Revenues	$ 104,395	$ 102,433	$ 1,962	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas	$ -					
5	Other O&M Expenses	$ (954,445)			$ 1,263		
6	Depreciation & Amortization	$ (495,289)				$ (196,266)	$ (299,023)
7	Taxes Other Than Income Taxes	$ (265,732)				$ (166,884)	
9	PRE-TAX OPERATING EXPENSES	$ (1,715,465)	$ -	$ -	$ 1,263	$ (363,150)	$ (299,023)
10	PRE-TAX OPERATING INCOME	$ 1,819,860	$ 102,433	$ 1,962	$ (1,263)	$ 363,150	$ 299,023
11	Income Taxes	$ 584,344	$ 39,537	$ 757	$ (487)	$ 140,169	$ 115,417
11	TOTAL OPERATING EXPENSES	$ (1,131,121)	$ 39,537	$ 757	$ 776	$ (222,981)	$ (183,606)
12	OPERATING INCOME	$ 1,235,516	$ 62,896	$ 1,205	$ (776)	$ 222,981	$ 183,606

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Incentive Compensation and SERP	Emergency Bill Assistance Expense	Remove Nonrecurring Severance Payment Expense	Overtime Payroll Expense	Payroll Tax Expense	Nonrecurring FERC Rate Case Legal Expense
		C-6	C-7	C-8	C-9	C-10	C-11
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (262,223)	$ 21,600	$ (52,388)	$ (123,010)		$ (311,051)
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes	$ (5,202)				$ (13,356)	
9	PRE-TAX OPERATING EXPENSES	$ (267,425)	$ 21,600	$ (52,388)	$ (123,010)	$ (13,356)	$ (311,051)
10	PRE-TAX OPERATING INCOME	$ 267,425	$ (21,600)	$ 52,388	$ 123,010	$ 13,356	$ 311,051
11	Income Taxes	$ 103,221	$ (8,337)	$ 20,221	$ 47,479	$ 5,155	$ 120,059
11	TOTAL OPERATING EXPENSES	$ (164,204)	$ 13,263	$ (32,167)	$ (75,531)	$ (8,201)	$ (190,992)
12	OPERATING INCOME	$ 164,204	$ (13,263)	$ 32,167	$ 75,531	$ 8,201	$ 190,992

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Property Tax Expense	Worker's Compensation Expense	Membership and Industry Association Dues	Fleet Fuel Expense	Postage Expense	Interest Synchronization
		C-12	C-13	C-14	C-15	C-16	C-17
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses		$ (34,234)	$ (26,868)	$ (52,439)	$ (115,095)	
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes	$ (80,290)					
9	PRE-TAX OPERATING EXPENSES	$ (80,290)	$ (34,234)	$ (26,868)	$ (52,439)	$ (115,095)	$ -
10	PRE-TAX OPERATING INCOME	$ 80,290	$ 34,234	$ 26,868	$ 52,439	$ 115,095	$ -
11	Income Taxes	$ 30,990	$ 13,214	$ 10,370	$ 20,240	$ 44,424	$ (118,085)
11	TOTAL OPERATING EXPENSES	$ (49,300)	$ (21,020)	$ (16,498)	$ (32,199)	$ (70,671)	$ (118,085)
12	OPERATING INCOME	$ 49,300	$ 21,020	$ 16,498	$ 32,199	$ 70,671	$ 118,085

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Capital Structure & Cost Rates

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule D

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	n/a	n/a	n/a	n/a
2	Long-Term Debt	$ 98,859	50.00%	6.60%	3.30%
3	Common Stock Equity	$ 98,859	50.00%	11.00%	5.50%
4	Total Capital	$ 197,718	100.00%		8.80%
	ACC Staff - Proposed				
5	Short-Term Debt	n/a	n/a	n/a	n/a
6	Long-Term Debt	$ 98,859	55.33%	6.60%	3.65%
7	Common Stock Equity	$ 79,804	44.67%	10.00%	4.47%
8	Total Capital	$ 178,663	100.00%		8.12%
9	Difference				-0.68%
10	Weighted Cost of Debt				3.65%

Notes and Source

Lines 1-4: UNS Gas Inc. filing, Schedule D-1
Lines 5-8: Staff witness David Parcell

UNS Gas, Inc.
Remove Construction Work in Progress

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B-1

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (7,189,231)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Remove GIS Deferral

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	Remove GIS Deferral	$ (897,068)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-2, page 2, line 16
B: Testimony of Staff witness Ralph Smith

FERC Account 183

UNS Gas, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 12/31/05

Line No.	Descrption	FERC	Per UNS Gas Pro Forma Test Year Amount		Staff Adjustments	Staff Adjusted	Expense Lag Days	Net Lag Days (RevLag - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.C)
	(A)		(A)		(B)	(C)	(D)	(E)	(F)	(G)
	Operating Expenses:									
	Non-Cash Expenses -									
1	Bad Debts Expense	904	$ 722,634	1a	1,263	723,897				$ -
2	Depreciation	403/404	7,950,183	1.4a	(196,266)	7,753,917				-
3	Amortization	406	(729,791)	1.4b	(299,023)	(1,028,814)				-
4	Deferred Income Taxes		3,178,719			3,178,719				-
	Other Operating Expenses -									
5	Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	(175,398)	7,112,347	24.50	14.45	0.0396	281,649
6	Incentive Pay (UNSG Direct Employees)	Multi	257,895	3a	(63,430)	194,466	267.00	(228.05)	(0.6248)	(121,502)
7	Purchased Gas	Calc	78,101,248	4a	148,392	78,249,640	30.97	7.98	0.0219	1,714,759
8	Office Supplies and Expenses	921	1,365,974	1.2a	(5,640)	1,360,334	20.72	18.23	0.0499	67,881
9	Injuries and Damages	925	574,128	1.2b	(34,234)	539,894	64.75	(25.80)	(0.0707)	(38,171)
10	Pensions and Benefits	926	2,452,071	1.2c	-	2,452,071	54.66	(15.71)	(0.0430)	(105,439)
11	Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A.	4,570,692	6a	(198,794)	4,371,899	44.91	(5.96)	(0.0163)	(71,262)
12	Property Taxes	408	4,103,376	1.4c	(247,174)	3,856,202	213.00	(174.05)	(0.4768)	(1,838,637)
13	Payroll Taxes	408	537,877	1.4d	(18,558)	519,320	19.30	19.65	0.0538	27,939
14	Current Income Taxes		(1,203,222)		2,397,424	1,194,202	41.42	(2.47)	(0.0068)	(8,121)
15	Interest on Customer Deposits	431	170,459	1.4e	-	170,459	182.50	(143.55)	(0.3933)	(67,042)
16	Other Operations and Maintenance	Multi	7,501,807	X.	(478,213)	7,023,594	53.10	(14.15)	(0.0388)	(272,515)
17	Total Operating Expenses		116,841,795		830,351	117,672,146				
	Other Cash Working Capital Elements:									
18	Interest on Long-Term Debt		5,334,825		305,935	5,640,760	91.62	(52.67)	(0.1443)	(813,962)
19	Revenue Taxes and Assessments	Calc	$ 18,788,535	L.	(6,405,918)	12,382,617	76.25	(37.30)	(0.1022)	(1,265,503)
20	Total Cash Working Capital - Calculated									$ (2,509,926)
21	Total Cash Working Capital - Per UNS Gas Filing, Schedule B-5, page 3 of 3									(3,280,886)
22	Adjustment to Cash Working Capital									770,960

Notes and Source
Col. A: UNS Gas filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Revenue Lag, in days 38.95
Col.B: Staff workpapers for CWC calculation

	Per Company	
ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas Lead/Lag Only	78,101,248	4a
ProForma Oper. Exp. To Tie Too - Excl Income Taxes	114,866,298	
Less: 1a, 1.4a, 1.4b, 2a, 3a, 4a, 1.2a, 1.2b, 1.2c, 6a, 1.4c, 1.4d, 1.4e	107,364,491	
Other O&M	$ 7,501,807	X.

Line 14, Col.C, Current income taxes:

Per UNS Gas	(1,203,222)	Col.A, line 14
Staff adjustments to net operating income statement	584,344	Schedule C
Income taxes for revenue increase	1,813,080	Schedule A-1
Total current income taxes for CWC calculation	1,194,202	

UNS Gas, Inc.
Accumulated Deferred Income Taxes

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B-4

Line No.	Description	Account	Amount (A)	Reference
	Adjustment to ADIT:			
1	For GIS deferral that UNS Gas added to rate base that Staff has removed	283	$ 346,250	Note A
2	SERP	190	$ (86,506)	Note B
3	Incentive Comp related ADIT	190	$ (64,408)	Note B
4	Total adjustment to ADIT		$ 195,336	

Notes and Source

A UNS Gas workpaper "H1 - GPS Reg Asset"

B Staff has removed SERP from operating expenses and allocated incentive comp expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

	Account and Description	Per Books (1)	UNS Gas Adjustment (2)	UNS Gas Adjusted	Staff Adjustment
	Account 190				
5	SERP	$ 88,747	$ (2,241)	$ 86,506 a	$ (86,506) B
6	Incentive Comp - PEP	$ 27,840		$ 27,840	$ (13,920) (3)
7	Long Term Incentive Comp	$ 100,975		$ 100,975	$ (50,488) (3)
8	Incentive Comp related ADIT	$ 128,815		$ 128,815	$ (64,408)

(1) Response to Staff DR 5.36
(2) UNS Gas, ADIT workpapers
(2a) UNS Gas workpaper "Pro Forma ADIT - Account 190" "SERP 12 D"
(3) Staff adjustment reflects a 50/50 allocation of incentive compensation responsibility between ratepayers and shareholders

UNS Gas, Inc.
Adjustment to Annualize Gas Retail Revenue

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Annualize Gas Retail Revenue	$ 725,682	A
2	Staff Recommended Annualized Gas Retail Revenue	$ 828,115	B
3	Adjustment to Annualized Gas Retail Revenue	$ 102,433	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 1, line 1

B: Total annualization adjustments calculated for the rate classes shown on Staff workpapers C-1.1, C-1.2 and C-1.3

FERC 480

UNS Gas, Inc.
Adjustment to Weather Normalization

Test Year Ended December 31, 2005

Line No.	Rate Class	UNS Gas Margin Weather Adjustment	Ratio of Weighted Average Annualized Customers	Staff Margin Weather Normalization	Adjustment to UNS Gas Proposed Weather Normalization
		(A)	(B)	(C)	(D)
1	Residential - 10	$ 369,269	1.004	$ 370,746	$ 1,477
2	Residential CARES - 12	$ 14,574	0.982	$ 14,312	$ (262)
3	Small Volume Commercial - 20	$ 95,408	1.009	$ 96,267	$ 859
4	Large Volume Commercial - 22	$ 67	1.000	$ 67	$ -
5	Irrigation - 60	$ 44	-	$ 44	$ -
6	Small Volume Public Authority - 40	$ 37,438	0.997	$ 37,326	$ (112)
7	Large Volume Public Authority - 42	$ 121	1.000	$ 121	$ -
8	Total	$ 516,921		$ 518,883	$ 1,962

Notes and Source
Col. A: UNS Gas proposed weather normalization adjustment
Col. B: Weighted average of Staff recommended annualized customers and UNS proposed annualized customers
Col. C: Col. A x Col. B
Col. D: Col. C - Col. A

FERC 480

UNS Gas, Inc.
Adjustment to Bad Debt Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-3

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Bad Debt Expense	$ 317,758	A
2	Recommended Staff Adjustment to Bad Debt Expense	$ 319,021	B
3	Adjustment to Bad Debt Expense	$ 1,263	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 5

B: Per Company's workpapers showing calculation of Bad Debt Expense adjustment (except where noted)

Line	Description	UNS Gas Bad Debt Adj.	Staff Bad Debt Adjustment	
4	Test Year Revenues	$ 136,799,000	$ 136,799,000	
5	Add: Late Fees and Miscellaneous Service Revenues	$ 1,446,000	$ 1,446,000	
6	Total	$ 138,245,000	$ 138,245,000	
	Rate Case Adjustments			
7	Customer Annualization	$ 1,680,578	$ 2,067,072	C
8	Weather Normalization	$ 1,826,135	$ 1,687,027	D
9	Reclass Related to Prior Periods (CARES Adjustment)	$ (203,181)	$ (203,181)	
10	Total Rate Case Adjustments	$ 3,303,532	$ 3,550,918	
11	Uncollectible Revenue Adjustment Base	$ 141,548,532	$ 141,795,918	L6 + L10
12	2 Year Average Retail Write Off Rate	0.51052%	0.51052%	
13	Pro Forma Bad Debt Expense	$ 722,634	$ 723,897	L11 x L12
14	Recorded Test Year Bad Debt Expense	$ 404,876	$ 404,876	
15	Staff Recommended Adjustment to Bad Debt Expense	$ 317,758	$ 319,021	L13 - L14

Note C
Customer
Annualization

Line		UNS Gas	Staff	
16	Revenue	$ 725,682	$ 828,115	Sch. C-1
17	Gas Cost	$ 712,128	$ 795,387	Staff workpaper
18	PGA Adjustor	$ 388,325	$ 443,570	Staff workpaper
19	Total	$ 1,826,135	$ 2,067,072	

Note D
Weather
Normalization

Line		UNS Gas	Staff	
20	Revenue	$ 516,921	$ 518,883	Sch. C-2
21	Gas Cost	$ 733,104	$ 735,952	Staff workpaper
22	PGA	$ 430,554	$ 432,192	Staff workpaper
23	Total	$ 1,680,579	$ 1,687,027	

FERC Account 904

UNS Gas, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (196,266)	A&B
2	CWIP Related Property Taxes	408	$ (166,884)	A&B
3	Total Adjustments		$ (363,150)	

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 4, lines 6 and 7
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Remove Amortization of Deferred GIS Cost

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Remove Company-proposed Amortization of Deferred GIS Cost	407	$ (299,023)	A

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 6

B: Amounts taken from UNS Gas Workpaper for GIS expenditures adjustment

FERC Account 874	Per UNS Workpaper	2005 Cost		Pre-2005 Cost
Materials & Supplies	$ (505)	$ -		$ (505)
Outside Services - Consultants	$ (746,792)	$ 133,238	*	$ (613,554)
Property Tax	$ (60)	$ -		$ (60)
Travel - Meals & Entertainment	$ (265)	$ 51		$ (214)
Pensions & Benefits Allocated	$ (6,994)	$ 688		$ (6,306)
Worker's Compensation	$ (14)	$ 2		$ (12)
Payroll Taxes - FICA	$ (2,312)	$ 198		$ (2,114)
Payroll Taxes - Unemployment	$ (366)	$ 50		$ (316)
Vacation & Sick Accrual	$ (563)	$ 563		$ 0
Wages - Regular	$ (32,074)	$ 3,452		$ (28,622)
Wages - Overtime	$ (2,138)	$ -		$ (2,138)
FERC 874 Total	$ (792,083)			$ (653,840)
FERC Account 920				
A&G Expense Transferred - UNSG	$ (22,922)	$ 400		$ (22,522)
A&G Expense Transferred - TEP	$ (25,362)	$ 3,108		$ (22,254)
FERC 920 Total	$ (48,284)			$ (44,775)
FERC 874 and 920 Total	$ (840,367)			$ (698,616)

* 2005 expenditures derived from Frontline Energy Services LLC invoices provided in response to RUCO 2.15

UNS Gas, Inc.
Incentive Compensation and SERP

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-6
Page 1 of 1

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Program (PEP)	$ (63,430)	A
2	Staff Adjustment to UES's Other Incentive Comp and SERP	$ (198,794)	B
3	Total Adjustment to Incentive Compensation Expense	$ (262,223)	
4	Adjustment to Taxes Other Than Income	$ (5,202)	A

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
874	Distribution - Mains & Services Expense	$ 20,731	50%	10,366
878	Distribution - Meter Expense	$ 16,844	50%	8,422
887	Distribution - Maintenance of Mains	$ 12,957	50%	6,479
903	Customer Records/Collections Expense	$ 29,800	50%	14,900
920	Administrative & General Salaries	$ 46,527	50%	23,264
		$ 126,859		$ 63,430
408	Taxes Other Than Income Taxes	$ 10,403	50%	5,202

B: Per UNS Gas Inc.'s response to STF 5.72

FERC Acct	Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
923	Supplemental Executive Retirement Plan (SERP)	$ 93,075	100%	$ 93,075
923	Officer's Long Term Incentive Plan	$ 108,920	50%	$ 54,460
923	Officer Portion of Performance Enhancement Plan (PEP)	$ 52,860	50%	$ 26,430
923	Deferred Compensation Plan	$ 11,315	50%	$ 5,658
923	Omibus Plan	$ 38,342	50%	$ 19,171
	Total	$ 304,512		$ 198,794

UNS Gas, Inc.
Emergency Bill Assistance Expense

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense	903	$ 21,600	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

UNS Gas, Inc.
Remove Nonrecurring Severance Payment Expense

Test Year Ended December 31, 2005

Line No.	Description	Amount	Account	Reference
1	Adjustment to Remove Severance Accrual Adjustment	$ (52,388)	857	A

Notes and Source

A: UNS Gas workpapers used to calculate its payroll adjustment

UNS Gas, Inc.
Overtime Payroll Expense

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Overtime Expense	$ 1,070,133	A
2	Staff Recommended Overtime Expense	$ 947,123	B
3	Adjustment to Overtime Expense	$ (123,010)	L2 - L1

Notes and Source

A: *UNS Gas workpaper used to calculate its payroll adjustment*

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

Line No.	Description	2004	2005	2 Year Average
4	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
5	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
6	Total Overtime Charged Directly to O&M	$ 781,386	$ 1,000,445	$ 890,915
7	Regular Annualized O&M Payroll	$ 5,472,931		
8	Adjusted 2005 Regular O&M Wages per Books	$ 5,148,145		
9	Increase to Regular O&M Payroll	1.06309		
10	Two Year Average Overtime Charged to O&M	$ 890,915		
11	Increase to Regular Payroll	1.06309		
12	Staff Recommended Increase to Overtime	$ 947,123		

UNS Gas, Inc.
Adjustment to Overtime Payroll Expense - Alternative Calculation

Docket No. G-04204A-06-0463
Schedule C-9
Page 2 of 2

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Total Overtime	$ 1,402,549	A
2	Staff Normalized Total Overtime	$ 1,220,536	B
3	Difference	$ (182,013)	L2 - L1
4	O&M Percentage	0.7630	C
5	Alternative Adjustment to Overtime Expense	$ (138,876)	

Notes and Source

A: UNS Gas workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
6	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
7	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
8	Overtime Charged to Non-O&M Accounts	$ 211,113	$ 303,260	$ 257,187
9	Total Overtime Charged Directly to O&M	$ 992,499	$ 1,303,705	$ 1,148,102
10	Regular Annualized O&M Payroll	$ 8,868,400		
11	Adjusted 2005 Regular O&M Wages per Books	$ 8,342,113		
12	Increase to Regular O&M Payroll	1.06309		
13	Two Year Average Overtime Charged to O&M	$ 1,148,102		
14	Increase to Regular Payroll	1.06309		
15	Staff Recommended Increase to Overtime	$ 1,220,536		

C:

16	Normalized Overtime Charged to O&M per Company	$ 1,070,133
17	Total Normalized Overtime per Company	$ 1,402,549
18	Percentage of Overtime Charged to O&M	0.7630

UNS Gas, Inc.
Payroll Tax Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-10
Page 1 of 1

Line No.	Description		Amount	Reference
1	Adjustment to Remove Severance Related Payroll Tax	$	(4,008)	A
2	Adjustment to Reduce Overtime Related Payroll Tax	$	(9,348)	B
3	Total Adjustment to Payroll Tax	$	(13,356)	

Notes and Source

A:	**Severance Accrual Adjustment (Schedule C-8)**			
4	Severance Accrual Adjustment	$	52,388	
5	OASDI Tax Rate		6.20%	
6	OASDI Payroll Tax Related to Severance Adjustment	$	3,248	
7	Severance Accrual Adjustment	$	52,388	
8	Medicare Tax Rate		1.45%	
9	Medicare Payroll Tax Related to Severance Adjustment	$	760	
10	OASDI Payroll Tax Related to Severance Adjustment	$	3,248	
11	Medicare Payroll Tax Related to Severance Adjustment	$	760	
12	Total Severance Related Payroll Tax Adjustment	$	4,008	L6 +L9
B:	**Overtime Adjustment (Schedule C-9)**			
13	Overtime Payroll Adjustment	$	123,010	
14	Allocator of wages in excess of $94,200		0.00817 *	
15	Wages in excess of $94,200	$	1,005	L13 x L14
16	Overtime Payroll Adjustment	$	123,010	
17	Wages in excess of $94,200	$	1,005	
18	OASDI Tax Base	$	122,005	L16 - L17
19	OASDI Tax Rate		6.20%	
20	OASDI Payroll Tax Related to Overtime Adjustment	$	7,564	
21	Overtime Payroll Adjustment	$	123,010	
22	Medicare Tax Rate		1.45%	
23	Medicare Payroll Tax Related to Overtime Adjustment	$	1,784	
24	Adjustment to Overtime Related Payroll Tax	$	9,348	L20 + L23

* Allocator of wages in excess of $94,200 calculated as follows:

Amounts taken from UNS Gas Payroll Tax adjustment workpaper

25	UNS Gas Unclassified Payroll in excess of $94,200	$	83,916	
26	Gross Annualized Payroll - per Company	$	10,270,949	
27	Allocator of wages in excess of $94,200		0.00817	L25 / L26

FERC 408

UNS Gas, Inc.
Nonrecurring FERC Rate Case Legal Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-11
Page 1 of 1

Line No.	Description	Amount	Reference
1	Adjustment to Remove FERC Rate Case Legal Expense	$ (311,051)	A

Notes and Source

A: Per UNS Gas Inc.'s response to STF 5.91
El Paso Gas Allocation/Rate Case settlement negotiations
through law firm of Fleischman & Walsh PLC

	Invoice Amount
May 2005	$ 87,269
August 2005	$ 28,463
September 2005	$ 56,612
October 2005	$ 32,331
November 2005	$ 28,712
December 2005	$ 39,129
December 2005	$ 38,535
	$ 311,051

FERC Account 923

UNS Gas, Inc.
Property Tax Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-12
Page 1 of 1

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Increase to Property Tax Expense	$ 1,591,370	A
2	Staff Proposed Increase to Property Tax Expense	$ 1,511,080	B
3	Adjustment to Property Tax Expense	$ (80,290)	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 5, line 7
B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

Line No.	**Utility Plant in Service Taxes**	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 12,668,650	$ 148,702,079	$ 9,770,270	$ 171,140,999
5	Less: Licensed Transportation in Rate Base	$ -	$ -	$(3,224,086)	$ (3,224,086)
6	Less: Land Cost & Rights of Way in Rate Base	$ (69,665)	$ (200,495)	$ (144,835)	$ (414,995)
7	Less: Environmental Property in Rate Base	$ (553,351)	$ (2,868,087)	$ (345,452)	$ (3,766,890)
8	Plus: Land FCV Per Arizona Dept. of Revenue		$ 697,806		$ 697,806
9	Plus: Materials & Supplies in Rate Base		$ 2,039,798		$ 2,039,798
10	Plant in Service Full Cash Value	$ 12,045,634	$ 148,371,101	$ 6,055,897	$ 166,472,632
11	Assessment Ratio*	24.0%	24.0%	24.0%	24.0%
12	Taxable Value	$ 2,890,952	$ 35,609,064	$ 1,453,415	$ 39,953,431
13	Average Tax Rate	9.4747%	9.4747%	9.4747%	9.4747%
14	Property Tax	$ 273,909	$ 3,373,852	$ 137,707	$ 3,785,468
15	Environmental Property in Rate Base	$ 553,351	$ 2,868,087	$ 345,452	$ 3,766,890
16	Statutory Full Cash Value Adjustment	50%	50%	50%	50%
17	Environmental Full Cash Value	$ 276,676	$ 1,434,044	$ 172,726	$ 1,883,445
18	Assessment Ratio*	24.0%	24.0%	24.0%	24.0%
19	Taxable Value	$ 66,402	$ 344,171	$ 41,454	$ 452,027
20	Average Tax Rate	9.4747%	9.4747%	9.4747%	9.4747%
21	Property Tax	$ 6,291	$ 32,609	$ 3,928	$ 42,828
22	Total Property Taxes	$ 280,200	$ 3,406,461	$ 141,635	$ 3,828,296
23	Property Taxes on Leased Property	$ -	$ -	$ 25,629 a	$ 25,629
24	Total Property Tax Expense	$ 280,200	$ 3,406,461	$ 167,264	$ 3,853,925
25	Less: Recorded Property Taxes Excluding Call Center	$ (135,825)	$ (2,082,996)	$ (124,024)	$ (2,342,845)
26	Property Tax Expense Adjustment	$ 144,375	$ 1,323,465	$ 43,240	**$ 1,511,080**

a: Property Tax for Leases calculated as follows (amounts taken from Company workpaper)

Line No.		Primary Value	Secondary Value	Total
	Cottonwood Lease			
27	Full Cash Value	$ 795,459	$ 1,016,515	
28	Assessment Ratio*	24.0%	24.0%	
29	Taxable Value	$ 190,910	$ 243,964	
30	Tax Rate	8.7284%	1.8218%	
31	Property Tax	$ 16,663	$ 4,445	$ 21,108
	Nogales Lease			
32	Full Cash Value	$ 397,182		
33	Assessment Ratio*	24.0%		
34	Taxable Value	$ 95,324		
35	Tax Rate	11.8563%		
36	Property Tax	$ 11,302		
37	Percentage Allocated to UNS Gas	40%		
38	Property Taxes Allocated	$ 4,521		$ 4,521
39	Total Lease Taxes			$ 25,629

* 2007 Arizona Statutory Assessment Ratio 24.0%

FERC 408

UNS Gas, Inc.
Worker's Compensation Expense

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Adjustment to Worker's Compensation Expense	925	$ (34,234)	A&B

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 2, line 5
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Membership and Industry Association Dues

Docket No. G-04204A-06-0463
Schedule C-14

Test Year Ended December 31, 2005

Line No.	Vendor	Amount	FERC Account
1	American Gas Association	$ 41,854	930
2	Less 40% Related to Lobbying & Advertising*	40%	
3	Adjusted American Gas Association	16,742	930
4	Arizona Utility Group	$ 500	930
5	Arizona Utility Investors Association	$ 2,500	930
6	Chino Valley Area Chamber of Commerce	$ 215	930
7	Coconino County Clerks of Superior Court	$ 18	921
8	Exchange Club	$ 375	921
9	Flagstaff Chamber of Commerce	$ 2,378	921
10	IBA Publishing Inc.	$ 325	930
11	Kingman Chamber of Commerce	$ 386	921
12	Kingman Rotary Club	$ 458	921
13	Mayer Area Chamber of Commerce	$ 72	930
14	Prescott Chamber of Commerce	$ 386	930
15	Prescott Valley Chamber of Commerce	$ 550	930
16	Seligman Chamber of Commerce	$ 40	930
17	Show Low Girls Soccer Booster Club	$ 25	930
18	Show Low Main Street	$ 375	930
19	U.S. Mexico Border Counties Coalition	$ 250	921
20	USDA Forest Service	$ 173	930
21	White Mountain Regional Development Corp.	$ 1,100	930
22	Total Membership and Industry Association Dues	$ 26,868	

		Total From Above	Adjustment
23	Total Amount Recorded in Account 921	$ 23,003	$ (23,003)
24	Total Amount Recorded in Account 930	$ 3,865	$ (3,865)
25	Total	$ 26,868	$ (26,868)

Notes and Source

Amounts taken from UNS Gas response to STF 5.61

* Percentage derived from NARUC Audit Reports on AGA Expenditures for 1998 and 1999 issued January 2000 and June 2001, respectively

UNS Gas, Inc.
Fleet Fuel Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-15
Page 1 of 1

Line No.	Description		Amount	Reference
1	UNS Gas Adjustment to Fleet Fuel Expense	$	73,726	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$	21,287	B
3	Adjustment to Fleet Fuel Expense	$	(52,439)	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 9

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment (except where noted)

4	Average operational FTE count for 2005		123.58	
5	Average technical FTE count for 2005		24.83	
6	Average construction FTE's for 2005		148.42	L4 + L5
7	2005 miles driven		2,228,658	
8	2005 mileage per Average Construction FTE		15,016	L7 / L6
9	2 month Average Construction FTE's for 2006		158	
10	Assumed 2006 mileage with 1st quarter staffing levels		2,365,055	L8 x L9
11	2005 Actual miles/gallon		9.60	
12	Calculated gallons purchased		246,360	L10 / L11
13	Average cost of fuel for October 2006 through January 2007	$	2.26	Note C
14	Cost of calculated gallons purchased	$	556,773	L12 x L13
15	Dollars purchased through Pro-Cards during 2005	$	37,491	
16	Pro forma fuel expenditures	$	594,264	L14 + L15
17	Test year expenditures	$	565,263	
18	Pro forma expenditure adjustment	$	29,001	L16 - L17
19	Percentage transportation allocation to O&M		73.4%	
20	Staff recommended pro forma adjustment to Fleet Fuel Expense	$	21,287	

C Cost of fuel from a Three Month Average Retail Price Chart through January 17, 2007 taken from ArizonaGasPrices.com

UNS Gas, Inc.
Postage Expense

Docket No. G-04204A-06-0463
Schedule C-16
Page 1 of 1

Test Year Ended December 31, 2005

Line No.	Description	Amount		Reference
1	UNS Gas Annualized Postage Expense	$ 529,380		A
2	Staff Annualized Postage Expense	$ 414,285		B
3	Adjustment to Postage Expense	$ (115,095)	a	L2 - L1

Notes and Source

A: UNS Gas workpaper used in calculating its Postage Expense adjustment

B: **Staff recommended Postage Expense Annualization**

Test Year Postage Expense	$ 386,673	
Postage increase effective January 8, 2006 ($.02 / $.37)	$ 1.05	
Increased Postage Expense	406,007	
Ratio of Weighted Average Annualized Customers	1.02039	b
Annualized Postage Expense per Staff	$ 414,285	

a: Allocation of Staff adjustment to FERC accounts

FERC 903	$ (109,455)	95.1%
FERC 921	$ (5,640)	4.9%
	$ (115,095)	100.0%

b: TY average and year end customers derived from the following rate classes per UNS Gas response to STF 11.10:

	Average	Dec. 2005
Residential - 10	118,821	121,125
Residential CARES -12	5,264	5,556
Small Volume Commercial - 20	10,849	11,017
Large Volume Commercial -22	10	11
Small Volume Public Authority - 40	1,042	1,051
Large Volume Public Authority - 42	6	5
	135,992	138,765

Additional Postage Expense through Customer Annualization 1.02039

UNS Gas, Inc.
Interest Synchronization

Docket No. G-04204A-06-0463
Schedule C-17

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	Adjusted rate base	$ 154,541,358	Schedule B
2	Weighted cost of debt	3.65%	Schedule D
3	Synchronized interest deduction	$ 5,640,760	Line 1 x Line 2
4	Synchronized interest deduction per UNS Gas	$ 5,334,825	Note A
5	Difference (decreased) increased interest deduction	$ 305,935	Line 3 - Line 4
6	Combined federal and state income tax rates	38.598%	STF 5.76, item 6
7	Increase (decrease) to income tax expense	$ (118,085)	

Notes and Source

A RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Also, UNS Gas filing, Schedule B-5, page 3 of 3, line 18

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER **31,1999**

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment.
	Institutional - to enhance the image of the natural gas industry as a business entity.
	Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

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AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
13	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/ 16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Excerpt from Florida PSC City Gas Company rate case 01152004

State of Florida

Public Service Commission

Capital Circle Office Center 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE:DECEMBER 23, 2003

TO:DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM:DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE:DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA:01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES:5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS:NONE

FILE NAME AND LOCATION:S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Attachment RCS-5
Copies of UNS Gas' Responses to Data Requests Referenced in Direct Testimony and Schedules of
Ralph C. Smith

Data Request No.	Subject	Page(s)
RUCO 2.15	Geographic Information System (GIS)	2-4
RUCO 1.10	Rate Base - GIS Deferral, Memo dated October 3, 2005, 2003-05 UNS Gas "GPS and Locate" Costs	5-11
STF 5.76	Errors in Filing Information	12-23
STF-5.72	Employee Benefits	24-28
STF 11.5 (c)	Incentive Compensation	29-30
STF 5.91	Legal Expense	31-32
RUCO 6.09	Proforma Adjustment Worker's Compensation Expense	33-34
RUCO 6.06	Proforma Adjustment Worker's Compensation Expense	35
STF 16.1	American Gas Association Dues	36-40
STF 5.28	Cost of Removal	41-42
STF 13.2	Cost Studies/Economic Analysis	43-44
STF 13.6	Incremental Contribution Study	45
STF 13.7	Change to Section 6.B.2b, impact on customers	46
STF 13.8	Change to Section 10C: Alignment Proposal, revision to billing terms	47
STF 13.9 (c)	Change to Section 10C: Due dates, late penalty charges	48-50
STF 13.10	Change to Section 10J, Electronic Billing	51-52
STF 13.11 (d)	Change to Section 11, Termination notice	53-55
RUCO 1.10	Cash Working Capital Lead/Lag Study Summary	56-57
STF 5.36	Accumulated Deferred Income Taxes	58-59
STF 11.10	Number of Customers by rate class	60-61
	Total Pages Including this Page	61

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO RUCO'S SECOND SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463

October 25,2006

2.15 Geographic Information System (GIS) Please provide the following information regarding the GIS:

a) Date the GIS entered service;

b) Account where the GIS resides (include an explanation of the logic for the account chosen);

a) Original cost of GIS;

d) Indicate if the GIS is being depreciated or amortized, and if so, at what rate, if not, why not;

e) Copy of all invoices that comprise the $897,068 in costs; and

e) Accumulated amortization or depreciation balance at 12-31-05.

RESPONSE: UNS Gas is still compiling information and the response will be provided at a later date.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger and Dallas Dukes

SUPPLEMENTAL RESPONSE:

a) The GIS entered service on July 1,2001.

b) The GIS resides in Account 391 per FERC Uniform System of Accounts.

c) The original cost of GIS was $1,158,035.

d) The GIS is depreciated at a rate of 13.92%.

e) See Bates Nos. UNSG (0463) 00112 to UNSG (0463) 00178 for copies of the invoices that comprise the $897,068 in costs. They total $746,776 of the total $897K sought for recovery. The difference represents labor, labor-related costs, and overheads.

f) The accumulated amortization balance at 12-31-05 was $718,676.

RESPONDENT: **Carl** Dabelstein

WITNESS: Karen Kissinger

TEP. Inc.
UNS Gas "GPS and Locale" Task Analysis
813112005

Project #	Task #	Task Description	Expenditures by Year 2003	2004	2005	Total
250912C	DA10000	Locate 6 GPS Existing Mains and Services	104,963.27	601,320.62	-23,058.13	729,342.02
250912A	DA10009	Locate & GPS Existing Mains and Services, Kingman & Havasu, Flag Admin		1,950.04	165,671.03	167,621.07
		Total	104,963.27	603,270.66	188,729.16	896,963.09

Invoices Provided

250912C	DA10000	Front Line Energy Costs	585,316.53	80%	of total Task Costs
250912A	DA10009	Front tine Energy Costs	161,460 00	96%	of total Task Costs
			746.776.53	83%	

DATE: October 3, 2005

TO: UNS Gas File

FROM: Steve K. Sims

Background

In 2003 UniSource Energy (UNS) created three subsidiaries to handle the acquisition of the Arizona gas and electric utility properties owned by Citizens Communications. The three subsidiaries are UniSource Energy Service (UES), a holding company, which owns the stock of UNS Gas and UNS Electric, the operating companies. On August 11, 2003, UNS Gas and UNS electric acquired the utility assets from Citizens. Absent an ACC order to the contrary, when a company acquires the operating assets of a utility regulated by the ACC, the acquirer is required to follow the regulatory accounting procedures used by the predecessor company.

UNS is a public company filing quarterly Forms 10-Q and annual reports on Form 10-K with the SEC. UES quarterly and annual financial data is reported in the segment information included in the Forms 10-Q and in the Form 10-K. UNS Gas prepares annual audited financial statements which are provided only to their lenders.

Issue

202

UNS Gas undertook a project to locate and GPS all of their existing service lines during 2003-2005 in order to update the data in the UNS Gas Global Information System (GIS). These costs were accounted for as capital costs and partially placed-in-service in 2005 with an in-service date of 12/31/03 with catch-up depreciation of approximately $50,000 recognized as of 8/31/05. The total cost of the project was $897,000 with approximately 83% of the cost, or $747,000, paid to Front Line Energy for locating and GPS'ing the lines. This project took place as a result of an Arizona Corporation Commission (ACC) compliance audit. The ACC compliance audit found that:

Maps available at the time of the audit and used by locating, leak survey, construction and emergency personnel fail to include all service lines.

Per discussion with Carl Dabelstein, Director of Regulatory Accounting, absent an ACC order to defer any costs the accounting treatment of the costs would be consistent with Generally Accepted Accounting Principles (GAAP). The FERC Uniform System of Accounts (USOA) does not specifically prescribe a procedure to be used in accounting for the costs of developing computer software, however, in its Order on Accounting for Pipeline Assessment Costs (copy attached) issued in Docket No. A105-1-000 on June 30, 2005, a specific reference to SOP 98-1 appears in footnote 8 on page 8 thereof. At the fall 2005 meeting of the NARUC Accounting Committee, Carl Dabelstein broached the subject of software development cost accounting with current FERC Chief Accountant, James Guest. Mr. Guest confirmed that, although the accounting has not yet been incorporated into the FERC USOA, that it is his position that companies subject to FERC regulation should follow the requirements of SOP 98-1.

SOP 98-1 – Accounting for the Costs of Computer Software Developed or Obtained for Internal Use – Paragraph .22 states:

The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, creation of new/additional data, and conversion of old data to the new system. Data conversion costs, except as noted in Paragraph .21, should be expensed as incurred.

The key guidance has been underlined. Any creation of new data should be expensed as incurred.

The misstatement to the financial statements as of December 31, 2004 is as follows:

UNS Gas/UES/UNS
- Overstatement of Total Utility Plant -$872,000
- Overstatement of Accumulated Depreciation and Amortization - $0
  (Accumulated Depreciation and Amortization is $0 due to the asset not being placed-in-service prior to 2005)
- Overstatement of cumulative Net Income of $527,000 of which $63,000 relates to 2003
- Understatement of cumulative Other Operations & Maintenance - $872,000

In accordance with Accounting Principles Board No. 20, *Accounting Changes,* (APB20) the misstatement is considered to be a correction of an error and should be accounted for as such. Paragraph 38 of APB 20 provides guidance on evaluating materiality of errors and states in part,

> "...a number of factors are relevant to the materiality of ... corrections of errors, in determining both the accounting treatment of these items and the necessity for disclosure. Materiality should be considered in relation to both the effects of each change separately and the combined effect of all changes. If a change or correction has a material effect on income before extraordinary items or on net income of the current period before the effect of the change, the treatments and disclosures described in this Opinion should be followed. Furthermore, if a change or correction has a material effect on the trend of earnings, the same treatments and disclosures are required. A change which does not have a material effect in the period of change but is reasonably certain to have a material effect in later periods should be disclosed whenever the financial statements of the period of change are presented."

Discussion

The following analysis reflects UNS, UES, and UNS Gas consolidated financial information. UNS Gas is a reportable business segment and contributes approximately 11% to UNS's consolidated operating revenues and comprises approximately 6.3% of its consolidated assets.

Financial Statements

In considering the materiality of the misstatement both quantitative and qualitative aspects need to be considered.

UNS Gas

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 8,382	1.25%	$ 63	$1,077	5.85%
2004	767	23,009	3.33%	463	5,703	8.12%
Total Misstatement	$ 872	$31,391	2.78%	$ 526	N/M	N/M

2.

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$ 167,871	$ (872)	$166,999	0.52%
Accumulated Depreciation and Amortization	(6,893)	0	(6,893)	0%
Total Utility Plant - Net	160,978	(872)	160,106	0.54%
Total Assets	201,353	(872)	200,481	0.44%

UNS Gas financial results are reported annually in audited financial statements prepared for lenders. The key impact to be considered is UNS Gas' ability to meet the financial covenants of the credit facilities and not the results of operations or the net income contribution to UNS Shareholders. As discussed below, the ability to satisfy these covenants has not been meaningfully affected by the misstatement. Based on the foregoing, the misstatements to the annual 2003 and 2004 financial statements are deemed to be immaterial.

UES

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 16,973	0.62%	$ 63	$3,010	2.09%
2004	767	46,984	1.63%	463	10,047	4.61%
Total Misstatement	$ 872	$63,957	1.36%	$ 526	N/M	N/M

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$284,271	$ (872)	$283,399	0.31%
Accumulated Depreciation and Amortization	(19,789)	0	(19,789)	0%
Total Utility Plant - Net	264,355	(872)	263,483	0.33%
Total Assets	336,131	(872)	335,259	0.26%

UES annual audited financial statements are provided to the lenders of UNS Gas and UNS Electric. UNS Gas financial results are also reported quarterly and annually in the segment information provided in the Forms 10-Q and Form 10-K. The annual information provided in the Form 10-K only reports Net Income. The segment footnotes in the UNS Form 10-Q report Income Before Income Taxes and Net Income for the quarterly and year-to-date periods appropriate for the quarter, and Total Assets as of the end of the quarter. Based on the

3.

above with O&M being understated by a maximum of 1.63%, a Net Income maximum misstatement of 4.61% and a Total Asset misstatement of .26%, it is not believed that any segment differences would have misled investors or changed their investment decision. The key impact to be considered is UNS Gas' ability to meet the financial covenants of the credit facilities, discussed below.

UNS

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 216,323	0.05%	$ 63	$46,470	0.14%
2004	767	252,711	0.30%	463	45,919	1.01%
Total Misstatement	$ 872	$469,034	0.19%	$ 523	N/M	N/M

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$3,873,467	$ (872)	$3,872,595	0.02%
Accumulated Depreciation and Amortization	(1,348,017)	0	(1,348,017)	0%
Total Utility Plant - Net	2,081,137	(872)	2,080,265	0.04%
Total Assets	3,175,518	(872)	3,174,646	0.03%

Based on the foregoing, the misstatements to the 2003 and 2004 UNS income statements are deemed to be immaterial. The misstatements attributable to the quarterly periods for UNS (the impacts of the misstatement in each quarterly period beginning in the third quarter of 2003 through 2004 are outlined in Appendix A) are also considered to be immaterial as Net Income is not misstated in any quarterly period more than 1.29%. Based on an annualized quarterly amount, the 2004 misstatement of Net Income is only 1.01%. Based on these considerations, the misstatement to the UNS income statement attributable to 2003 and 2004 are deemed to be immaterial.

Based on the foregoing, the misstatements to the December 31, 2004 balance sheets are deemed to be immaterial as the misstatement to Total Utility Plant was .02% and to Total Assets of .03%

Impact on Third Quarter 2005

As provided for in Staff Accounting Bulletin Topic 5.F., we must consider the impact on the third quarter and nine months ended September 30, 2005 results for UNS if the misstatement is corrected in September 2005. The misstatement amounts shown below are net of the catch-up depreciation that has been recognized for the portion of the asset that was placed in-service on July 19, 2005 with an in-service date of 12/31/03.

UNS Gas is a small segment of UNS Consolidated at 6.3% of total assets. The third quarter 10-Q segment disclosure for UNS Gas net income is $2,000,000 which includes this write-off. As such, the write-off amount is considered immaterial to the segment disclosure. Year-end 2005 impact of this adjustment combined with other adjustments for UNS Gas will be addressed in a separate memo.

4.

UNS	3rd Quarter 2005 Projected: Unadjusted	Misstatement	As Adjusted	% of Adjusted Amount
Other O&M	$56,703	$ 847	$57,550	1.47%
Total Operating Expense	286,571	847	287,418	0.29%
Operating Income	56,701	(847)	55,854	1.52%
Net Income	15,733	(542)	15,191	3.57%

UNS	Nine Months Ended September 30, 2005 Projected: Unadjusted	Misstatement	As Adjusted	% of Adjusted Amount
Other O&M	$179,444	$ 847	$180,291	.47%
Total Operating Expense	763,569	847	764,416	0.11%
Operating Income	141,223	(847)	140,376	.60%
Net Income	21,418	(542)	20,876	2.60%

The quantitative effects on the quarterly and nine-month periods ended September 30, 2005 reflect a change from reporting approximately $21.4 million and $15.7 million of Net Income to reporting approximately $20.9 million and $15.2 million of Net Income, respectively. Further, as outlined above, the misstatements to Total O&M, Total Operating Expense and Operating Income are NOT considered quantitatively material as NONE of the impacts exceed 1.52%. The correction of the error in the third quarter does not result in a material impact on Net Income.

As previously noted, in evaluating the materiality of a misstatement, qualitative considerations need to be considered as well as the quantitative aspects. SEC Staff Accounting Bulletin 99 – Materiality (SAB 99) provides both quantitative and qualitative guidance as to whether a financial statement change should be considered material. In evaluating qualitative aspects, SAB 99 indicates that the registrant should consider whether the misstatement arises from an item capable of precise measurement or whether it arises from an estimate. In addition, SAB 99 asks the registrant to consider whether the misstatement or change has any of the following implications:

- Masks a change in earnings or other trends;
- Hides a failure to meet analysts' consensus expectations for the enterprise;
- Changes a loss into income or vice versa;
- Affects compliance with regulatory requirements;
- Affects compliance with loan covenants or other contractual requirements;
- Increases managements' compensation; or
- Conceals an unlawful transaction.

Due to the immateriality of the error to UNS, we do not believe that the error masks a change in earnings, does not hide a failure to meet analysts' consensus expectations for the enterprise, it does not change income into a loss, it does not affect compliance with regulatory requirements, it did not increase management compensation and does not conceal an unlawful transaction. The affect on compliance with loan covenants is discussed below.

UNS Gas Debt Compliance

We have reconsidered UNS Gas interest coverage ratio, capitalization ratio and net worth tests related to all financial covenants of their credit agreements, noting that these adjustments would not have affected compliance with any of these loan covenants as follows:

- The interest coverage ratio is a ratio of EBITDA to Interest Expense (excluding the effect of Debt AFDC). EBITDA is overstated as a result of this misstatement. EBITDA before adjustment was $8M in 2003 and $24M in 2004. The pre-tax adjustment of $105K and $767K in 2003 and 2004, respectively, would not significantly affect the ratio.

- The capitalization ratio is a ratio of total indebtedness to total capitalization. Since total capitalization was overstated, this means that UNS Gas' debt as a percent of total capitalization would have increased in each period, had the adjustment been made in 2004. However, UNS Gas Total Assets misstatement of .26% would not have materially changed the ratio.

- UNS Gas actual net worth test compares actual net worth to a minimum amount. In all cases, although Net Income decreased after adjusting for the misstatement, the net worth amount would be lower in each period but would still have met minimum requirements.

There are no dividend restrictions or other contractual requirements that would have been affected by the misstatements. In each year, our performance would have been slightly worse. However, we were well within compliance with all applicable requirements, a slight decrease would have made no difference in the evaluation of UNS Gas, UES or UNS's operations. Further, it would not have been in management's personal interest to overstate earnings in any period nor would it have impacted their compensation. In addition, this error was not the result of any fraudulent activity or made in an attempt to conceal an unlawful transaction.

Summary of Financial Statement Impact

In addition, we considered financial measures that investors believe are significant and place reliance on in making their investment decisions. This includes not only GAAP measures such as Cash Flows from Operations and the Ratio of Earnings to Fixed Charges (RETFC), but certain non-GAAP measures such as Adjusted EBITDA as outlined in Item 6 of our 2004 Annual Report on Form 10-K. This change would not have any impact on Cash Flows from Operations or EBITDA and based on recalculating the RETFC, the misstatement did not have a significant or adverse impact on this measure. Accordingly, we do not believe that this change would have an impact on investor decisions. No qualitative considerations that would affect the decisions of a financial statement reader have been identified.

Based on the foregoing considerations, and also taking into account the following matters, the misstatement is not deemed to be qualitatively material for the quarter or nine months ended September 30, 2005: The misstatement does not mask any identifiable trends in UNS' third quarter earnings. Further, because of the seasonal nature of UNS's operations, projections provided to analysts are provided only on an annual basis. Analysts and investors are primarily concerned with the cash flows of the company and the misstatement has no effect on the reported or future cash flows. Further, to the extent that there are investors looking at earnings per share, there are many other variable factors in the operations of UNS that can have significant effects on EPS and we do not believe that the effect of recording the misstatement in the second quarter of 2005 masks any trends in EPS. Accordingly, we do not believe that the misstatement has a material impact on the quarter or nine months ended September 30, 2005.

Based on our consideration of both the quantitative and qualitative effects of the misstatement, we believe that the information above supports the conclusion that the financial statement differences are not material to the financial statements as of September 30, 2005 or for the quarterly period and nine months then ended. Note that ABP 28, *Interim Financial Reporting,* paragraph 29 requires disclosure of corrections that are material with respect to an interim period even though they are not material to the estimated income for the year or to the trend of earnings. Because the corrections are not considered material to the quarter and nine months ended September 30, 2005, no disclosures in our Third Quarter Report on Form 10-Q are considered necessary.

6.

Internal Controls

On June 5, 2003, the SEC issued final rules under Section 404 of the Sarbanes-Oxley Act requiring companies to file in their annual reports, a report of management on the company's internal control over financial reporting. Part of the required content in the report is a disclosure of any material weaknesses in the system. An internal control deficiency is a flaw in either the design or operation of a control policy or procedure that has a negative effect on this process. Consequently, we must determine if the internal control deficiency is inconsequential, significant or material.

As previously noted, the misstatement is not deemed to be material to the financial statements for the year or the quarter ended September 30, 2005. In addition, the misstatements were not intentional and have a nominal effect on earnings.

The Public Company Accounting Oversight Board (PCAOB) provides guidance for evaluating control deficiencies in Standard No. 2 as updated as of December 3, 2004 (AS2). Paragraph 23 of AS2 indicates that "The same conceptual definition of materiality that applies to financial reporting applies to information on internal control over financial reporting, including the relevance of both quantitative and qualitative consideration." In addition, we need to consider the likelihood that the deficiency could result in a misstatement and the magnitude of the potential misstatement. Several factors affect the likelihood including the nature of the related accounts, the cause of known exceptions, and the possible future consequences.

Based on review of the relevant considerations, we have concluded that an error of this kind is unlikely to happen again. The misstatement occurred due to a transfer of a task and the continued use of that task for cost accumulation from Citizens at acquisition. A second task for the work was created by Plant Accounting personnel prior to institution of the Capital Work Order Approval decision tree. The process of using the Capital Work Order Approval decision tree along with CON-GA-17 "Computer Software Costs" would have identified the work order as O&M and alerted the Plant Accounting personnel to the incorrect conversion and use of the previous work order. Steps have been taken to ensure that current Plant Accounting staff have been adequately trained on CON-GA-17 and its' implications when making the Capital vs O&M decision. During 2004, management evaluated and tested controls in place to ensure compliance with GAAP. Our testing of both the design and effectiveness of such controls noted no deficiencies.

Because the appropriateness of our accounting for the UNS Gas "GPS and Locate" costs was reconsidered in connection with UNS Electric's request to do the same task, our evaluation of the magnitude of a potential error should consider how in the absence of such analysis we would have identified the misstatement. Our current control processes require the completion of a Plant Accounting Work Order Creation - Capital Work Order Approval Decision Tree that is checked and reviewed for task creation. This review was not conducted in 2003 when the tasks were migrated from Citizens to TEP at the time of acquisition on August 11, 2003. Accordingly, in drawing a conclusion as to the maximum amount of potential misstatement we believe that the current process would have identified the task as O&M on the front end and appropriately charged to O&M.

Based on the foregoing, we do not believe that the control deficiency is material and therefore the deficiency does not constitute a material weakness. Note however, the deficiency is considered to be a significant deficiency and will be appropriately reported to the audit committee as well as the independent auditors.

Conclusion

We have carefully considered both quantitative and qualitative aspects of the misstatement of the UNS Gas "GPS and Locate" costs and believe that the error is not material to the respective financial statements for all periods considered. Accordingly, it is deemed acceptable to record the correcting adjustment in the third quarter of 2005.

cc: Peggy Denny, Karen Kissinger, Dave Grzybowski, Brian Hagues (PwC), David Eberhardt (PwC)

7.

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

STP 5.76 Filing Information. As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

RESPONSE: At the present time, UNS Gas has identified the following errors in its filing:

1. Exhibit TVL-2 to Mr. Tobin L. Voge's Direct Testimony should be replaced in its entirety with Exhibit TVL-2A, provided on the enclosed CD as STF 5.76 (EXHLBIT TVL-2A). The Throughput Adjustment (line 7 and line 9) should be a positive, not negative, number. The Exhibit is <u>not</u> identified by Bates numbers.

7 The O&M expenses referenced in Mr. James S. Pignatelli's Direct Testimony. page 3, line 24, should be $38,740,547, as presented in Schedule C-1, line 9.

3. The customer base referenced in Mr. Gary A. Smith's Direct Testimony, page 2, line 26, should be 131,474.

4. The targeted annual savings referenced in Mr. Smith's Direct Testimony, page 15, line 9, should be 36,056 therms.

5. Exhibit GAS-1 to Mr. Smith's Direct Testimony should be replaced in its entirety with Exhibit GAS-1A, provided on the snclosed CD as STF 5.76 (EXHIBIT GAS-1A). The Commercial HVAC Retrofit Program's Annual Therms should be 36,056, the TRC Ratio should be 1.46 and the PT Ratio should be 3.17. The Commercial & Industrial Gas Subtotal's Annual Therms should be 78,862, the TRC Ratio should be 1.36 and the PT Ratio should be 2.99. The Exhibit is <u>not</u> identified by Bates numbers.

6. On schedule A-3, the effective tax rate should be 38.598 percent times the taxable income as percent of 99.40. This would result in a gross conversion factor of 1.6370 rather than 1.6649. See STF 5.76 (6), Bates No. UNSG(0463)03778 to UNSG(0463)03779, on the enclosed CD for backup documentation.

7. Schedule B-5, line 19, "Revenue Taxes and Assessments," should be $11,966,406 as opposed to $18,788,535. This changes the cash working capital (Schedule B-5, line 20) to ($2,586,909) as opposed to ($3,230,886). This also changes pro forma current income taxes

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

(Schedule B-5, line 14) to ($1,212,062) as opposed to 3780
($1,203,222). See STF 5.76, Bates Nos. UNSG(0463)0~~3790~~ to UNSG(0463)3782, on the enclosed CD for backup documentation.

8. In the Company's Schedule H support workpapers, Column 21, line 15, a negative $54,558 was inadvertently entered. The Residential rate impact was minimal. This was addressed in the Company's response to 2.17 in RUCO's second set of data requests.

RESPONDENT: Legal Department

EXHIBIT
TVL-2A

Example of Throughput Adjustment Calculation

Line	Residential (R-10 and R-12)	
1	Test Year Throughput (Therms)	70,234,286
2	Test Year Average Number of Customers	124,085
3	Test Year Use Per Customer (Line1/Line 2)	566.02
4	Hypothetical 2006 UPC (1)	560.92
5	Difference in UPC (Line 4 - Line 3)	(5.09)
6	Margin Rate (per Therm)	$0.1862
7	Throughput Adjustment (Line 2 x Line 5 x Line 6 x (-1))	$117,699
8	Projected 12 month Throughput (Therms) (2)	75,965,404
9	Throughput Adjustment per Therm (Line 7/Line 8)	$0.0015

Line	Small Volume Commercial (C-20)	
1	Test Year Throughput (Therms)	28,801,436
2	Test Year Average Number of Customers	10,849
3	Test Year Use Per Customer (Line1/Line 2)	2654.75
4	Hypothetical 2006 UPC (3)	2617.59
5	Difference in UPC (Line 4 - Line 3)	(37.17)
6	Margin Rate (per Therm)	$0.2637
7	Throughput Adjustment (Line 2 x Line 5 x Line 6 x (-1))	$106,329
8	Projected 12 month Throughput (Therms) (4)	30,259,509
9	Throughput Adjustment per Therm (Line 7/Line 8)	$0.0035

Line	Small Volume Public Authority (PA-40)	
1	Test Year Throughput (Therms)	5,743,485
2	Test Year Average Number of Customers	1,042
3	Test Year Use Per Customer (Line1/Line 2)	5511.98
4	Hypothetical 2006 UPC (5)	5407.25
5	Difference in UPC (Line 4 - Line 3)	(104.73)
6	Margin Rate (per Therm)	$0.2712
7	Throughput Adjustment (Line 2 x Line 5 x Line 6 x (-1))	$29,595
8	Projected 12 month Throughput (Therms) (6)	5,858,929
9	Throughput Adjustment per Therm (Line 7/Line 8)	$0.0051

Notes
(1) Decline of 0.9%, based on the average year over year change in residential UPC years 1996 to 2005.
(2) Based on a 4.0% annual growth rate.
(3) Decline of 1.4%, based on the average year over year change in total commercial UPC years 1996 to 2005.
(4) Based on a 2.5% annual growth rate.
(5) Decline of 1.9%, based on the average year over year change in total public authority UPC years '96 to 05
(6) Based on a 1.0% annual growth rate.

EXHIBIT

GAS-1A

Residential Programs

Programs by Market or Customer Segment	Program Name	Residential Electric Program Description	Proposed Average Annual Budget	Targeted Annual Savings	Benefit Costs Ratios
Residential Gas	Residential Furnace Retrofit	• Provides prescriptive incentives for residential single and multifamily home owners for energy efficiency improvements in residential gas fueled furnace applications. • Utilizes the existing UES online 'Residential Energy Advisor', or Department of Energy online energy audit, as part of the program application process. • Provide training, qualification and promotion of contractors who are knowledgeable and meet UES standards installing and operating high efficiency HVAC systems. • All residential structures in the UNSE and UNSG service territories served by UESG gas are eligible for the furnace efficiency measures. • Annual installation of approximately 800 furnaces with 90% or greater AFUE ratings.	$204,243	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 74,240	TRC Ratio = 1.26 PT Ratio = 2.23
	Residential New Construction	• Provides prescriptive incentives to home builders for installation of energy efficiency measures in new residential construction projects. • Provide educational and promotional pieces and design tools to assistance to developers of new residential structures and associated middle market trade allies (A&Es, contractors, etc.) with the installation of high-efficiency homes that meet or exceed the UNSG Efficient Home and ENERGY STAR program standards. • Uses the UNSG Efficient Home (Energy Star) program savings measures, plus additional appliance measures. • Provides incentives to builders to install Energy Star labeled dishwashers, clothes washers, and refrigerators. • All new single family and multifamily buildings in the UNSE and UNSG service territories are eligible. • Annual participation is estimated to be 5% of new units, or approximately 580 homes in 2007.	$418,201	Coincident Peak kW = 914 Annual kWh = 1,415,646 Annual Therms = 72,651	TRC Ratio = 1.98 PT Ratio = 4.06
Residential Gas Subtotal			$622,444	Coincident Peak kW = 914 Annual kWh = 1,415,646 Annual Therms = 146,891	TRC Ratio = 1.7[illegible] PT Ratio = 3.2[illegible]

Commercial Programs

Programs Organized by Market or Customer Segment	Program Name	Commercial Gas Program Description	Proposed Average Annual Budget	Targeted Annual Savings	Benefit Costs Ratios
C&I Gas	Commercial HVAC Retrofit	• Provides prescriptive incentives for business owners for energy efficiency improvements in gas fueled heating (space and water) applications. • Utilizes the existing UES online 'Business energy Advisor', or Department of Energy online energy audit, as part of the program application process. • Provide training, qualification and promotions of contractors who are knowledgeable and meet UES standards • Participating allies will be allowed to participate in a qualified allies referral program • The target marker includes all commercial facilities in the UNSE and UNSG service territories served by UESG gas are eligible for the efficiency measures • Annual participation is estimated at approximately 130 facilities.	$150,500	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 36,056	TRC Ratio = 1.46 PT Ratio– 3.17
	Commercial Gas Cooking Efficiency	• Provides prescriptive incentives for business owners for energy efficiency improvements in commercial gas fueled cooking applications. • The target market includes all commercial kitchens in the UNSE and UNSG service territories served by UNSG gas are eligible for the efficiency measures • The market for participating facilities in all UES service territories is estimated at 700 restaurants, and numerous kitchens located in schools, hospital, and lodging facilities.	$143,672	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 42,806	TRC Ratio = 1.16 PT Ratio = 2.81
Commercial & Industrial Gas Subtotal			$204.172	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 78,862	TRC Ratio = 1.36 PT Ratio = 2.99

Revised 8/11/06

Schedule C-3
Page 1 of 1

UNS Gas, Inc
Computation of Gross Revenue Conversion Factor
Test Year Ended December 31, 2005

Line No	Description	Percentage of Incremental Gross Revenues		Line No.
1	Gross Revenue	100.00%		1
2	Less: Uncollectible Revenue	0.51%		2
3	Taxable Income as a Percent	99.49%		3
4	Less: Federal (32.50%) and State Income 21%) (Combined Effective Tax Rate = 39.629%)	38.40%		4
5	Change in Net Operating Income	61.09%		5
6	Gross Revenue Conversion Factor	1.6370	(a)	6

38.598 1a
x.9949
38.40%

(a) Line No 1 divided by line No. 5.

Supporting Schedules
N/A

Recap Schedules
A-1

STF 5.76-6

Attachment RCS-5
Page 19 of 61

UNSG0463/03778

UNS Gas, Inc.
Tax Rnlc
2005 Test Year

G:\TAXSVCS\Rate Case\Rate Case - UNSG 2005 TY\[Schedule M Items xls]1 - Current Income Taxes

Statutory AZ Corporate Tau Rate	*6 968%*
Statutory Federal Rate, Income < $10,000,000	34.000%
Less: State Tax Deduction Benefit	-2.370%
Federal Rnte after benefit of state deduction	31 630%
Total Combined Tax Rate	38.598% A

1.

UNS GAS
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 12131105

Description	FERC	Pro Forma Test Year Amount		Revenue Lag Days		Expense Lag Days		Net Lag Days (Col. C - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col. B)
(A)		(B)		(C)		(D)		(E)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 722,634	1a							$
Depreciation	403/404	7,950,183	1.4a							
Amortization	406	(729,791)	1.4b							
Deferred Income Taxes		3,178,719								
Other Operating Expenses -										
Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	38.95	C	24.50	E.	14.45	0.0396	288,595
Incentive Pay (UNSG Direct Employes)	Multi	257,895	3a	38.95	C.	267.00	F	(228.05)	(0.6248)	(161,133)
Purchased Gas	Calc	78,101,248	4a	38.95	C	30.97	D.	7.98	0.0219	1,711,508
Office Supplies and Expenses	921	1,365,974	1.2a	38.95	C	20.72	H	18.23	0.0499	68,162
Injuries and Damages	925	574,128	1.2b	38.95	C.	64.75	H.	(25.80)	(0.0707)	(40,591)
Pensions and Benefits	926	2,452,071	1.2c	38.95	C	54.66	H	(15.71)	(0.0430)	(105,439)
Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A	4,570,692	6a	38.95	C.	44.91	G	(5.96)	(0.0163)	(74,502)
Property Taxes	408	4,103,376	1.4c	38.95	C	213.00	I	(174.05)	(0.4768)	(1,956,490)
Payroll Taxes	408	537,877	1.4d	38.95	C.	19.30	I.	19.65	0.0538	28,938
Current Income Taxes		(1,212,062)	2c	38.95	C.	41.42	I.	(2.47)	(0.0068)	8,242
Interest on Customer Deposits	431	170,459	1.4e	38.95	C	182.50	J.	(143.55)	(0.3933)	(67,042)
Other Operations and Maintenance	Multi	7,501,808	X	38.95	C.	53.10	K.	(14.15)	(0.0388)	(291,070)
Total Operating Expenses		116,832,955								
Other Cash Working Capital Elements:										
Interest on Long-Term Debt		5,357,726	2b.	38.95	C.	91.62	J.	(52.67)	(0.1443)	(773,120)
Revenue Taxes and Assessments	Calc	$ 11,966,406	L	38.95	C.	76.25	I.	(37.30)	(0.1022)	(1,222,967)
Total Cash Working Capital			1a							$ (2,586,909) 2a

ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas Lead/Lag Only	78,101,248	4a
ProForma Oper Exp To Tie Too - Excl Income Taxes	114,866,298	
Less 1a 1.4a 1.4b 2a 3a 4a, 1.2a 1.2b 1.2c 6a 1.4c 1.4d 1.4e	107,364,490	
Other O&M	$ 7,501,808	X.

STF 5.76 - 7

UNSG0463/03780

UNSG Rate Case
Simultaneous Equation

I = Synchronized Interest Deduction for Tax
I =Weighted Cost of Debt x (Rate Base Excluding Working Capital + W)

Weighted Cost of Debt =				3.30%
Rate Base Excluding Cash Working Capital				$ 164.942.248
I =	$ 5,443,094.18	+	0.0330 W	

T = Current Income Taxes
T = Effective Tax Rate x (Taxable Income Before 'I' - 'I') - Tax Credits

Effective Tax Rate =					38.598%
Taxable Income Before Synchronized Interest =					$ 2.226,575
Tax Credits =					$ 3.500
Weighted Cost of Debt =					3.30%
T =	$ 855,913.42	less	$ 2,100.925.49	less	0.01273734 W
T =	$ (1,245,012.07)	less	0.01273734 W		

W = Cash Working Capital
W = CWC before I & T plus (L&L rate x 'I') plus (L&L rate x T)

Cash Working Capital Excluding I & T =					$ (1.822.031)
Lead/Lag Factor Current Income Taxes =					(0 0068)
Lead/Lag Factor Interest Long Term Debt =					(0.1443)
W =	$ (2,599,003)	plus	(0.004762) W +		0.0000866 W
	1.0046753 W =	$	(2,599.003)		
W =	(2,586,909)	a			

I =	$ 5,443,094.18	plus	(85.367.99)
I =	$ 5,357,726	b.	

T =	$ (1,245,012.07)	less	(32,950.34)
T =	$ (1,212,062)	c.	

2.

UNS Gas
2006 Rate Case
Lead/Lag Study
Revenue Tax Calculation

	2005	
States Sales Tax - Billed	$ 7,110,645.39	1.2a
City Sales Tax - Billed	$ 1,008,729.11	2.2a
County Sales Tax - Billed	$ 864,480.57	3.2a
Sales Tax - Unbilled	Note A.	5.2a
Franchise Taxes	$ 2,308,006.05	6.2a
ACC Assessment	$ 379,665.78	7.2a
Total Revenue Taxes	$ 11,671,526.90	
Total Retail Revenue	$ 138,798,513.00	8a
Effective Revenue Tax Percentage	8.41%	

Test Year Retail Sales Revenue	$ 138,798,513.00	
Customer Annualization Adj - Margin	$ 725,682.00	9a
Est. Customer Annualization Adj. - Fuel Cost Rev	$ 1,100,453.00	9b
Weather Normalization Adj - Margin	$ 516,921.00	10a
Est. Weather Normalization Adj - Fuel Cost Rev	$ 1,163,658.00	10b
Estimated Pro Forma Retail Revenues	$ 142,305,227.00	
Effective Revenue Tax Percentage	8.41%	
Estimated Revenue Taxes	**$ 11,966,405.47**	a.

Note A. Initial preparer included gross sale tax accrued on unbilled. Net is the only amount applicable and is immaterial so I excluded sales tax on unbilled completely. The initial workpaper had an effective rate of 13.20% which was grossly overstated

Dallas
Dukes

1.

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 5,2007**

STF 5.72

Employee Benefits. List and describe all retirement and incentive programs available to Company officers and employees.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.
b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE:

UNS Gas is in the process of gathering information and will provide the response to this data request as soon as the compilation is complete.

SUPPLEMENTAL RESPONSE:

UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNS Gas.

Incentives

UNS Gas non-union employees participate in UES' Performance Enhancement Program ("PEP"). The structure determines eligibility for certain bonus levels by measuring UES' performance in three areas:

- financial performance,
- operational cost containment, and
- core business and customer service goals.

Levels of achievement in each area are assigned percentage-based "scores". Those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15% to 150 % of the targeted payment level.

The financial performance and operational cost containment components each make up 30% of the bonus structure, while the core business and customer service goals account for the remaining 40 %.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages as a percent of base salary range from 3% - 14% for regular non-union employees, and 25% - 80% for Managers and Officers. Bonus percentages as a percent of base salary are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 5,2007**

payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs

UNS Gas employees are eligible to participate in the UES Pension Plan. For a description of this plan, please see STF 5.71 (Final UES Pension SPD v1 6-28-2004) on the enclosed CD. Additionally, UNS Gas employees are eligible to participate in the Tucson Electric Power Company ("TEP") 401(k) Plan as described below:

TEP 401(K) Plan

TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches 50 cents on the dollar, up to the first 6% of pay saved, in the 401(k) Plan for UNS Gas employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested.

TEP Salaried Employees Retirement Plan ("Salaried Plan")
(This description is included because some cost is allocated back to UES for officer participation.)

The Salaried Plan provides an annual income based on the following formula:

1.6% *times* Final Average Pay

times

Years of Service (up to 25 years)

Final average pay is the average of basic monthly earnings, on the first of the month following the employee's birthday, during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement.

Years of service are based on the employee's years and months of employment with TEP or a participating affiliated corporation. The

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 5,2007

employee is vested in his or her retirement benefit after five years of service.

The maximum benefit available under the plan is an annual income of 40% of final average pay. Plan compensation for purposes of determining final average pay is limited to IRS compensation limits (Code Section) 401(a)(17). In addition, contributions to the UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan") are not considered eligible compensation under the Salaried Plan.

<u>TEP Excess Benefit Plan ("Excess Plan")</u>
(This description is included because some cost is allocated back to UES for officer participation).

The Excess Plan provides benefits to officers and other highly compensated employees in addition to the benefits payable under the Salaried Plan.

Compensation used to determine final average pay under the Salaried Plan is limited by annual IRS compensation limits (Code Section) 401(a)(17)), and is further reduced by any contributions to the Deferred Compensation Plan.

The Excess Plan retirement benefit is calculated using the Salaried Plan formula without regard to the IRS limits on compensation, voluntary salary reductions to the Deferred Compensation Plan, and the annual incentive bonus is added to the earnings rate.

The retirement benefit payable from the Excess Plan will be reduced by the benefit payable from the Salaried Plan.

<u>UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred compensation Plan")</u>

The Deferred Compensation Plan allows participants (Directors, Officers and Managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis.

11,315

<u>Salary and Bonus Deferral</u>
A participant may elect to defer a percentage of their salary or bonus up to 100%. The minimum salary deferral amount is $3,500. Pay deferred

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
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January 5,2007**

under the plan is not included in W-2 earnings. Therefore, deferrals are not subject to federal or state income taxes at the time of deferral. However, deferred pay is subject to FICA and Medicare taxes in the year of deferral.

401(k) Excess Company Match
Limits on contributions to the TEP 401(k) Plan may keep highly compensated employees from receiving the full dollar-for-dollar Company match. If employees maximize their 401(k) deferral opportunity ($15,000 in 2006), the Company will contribute an amount to the Deferred Compensation Plan equal to the additional matching contribution that they would have received under the 401(k) Plan if their compensation in excess of the legal limitation ($220,000 in 2006) had been taken into account.

Receiving Account Balance
Full account balance will be distributed following retirement or termination. In the event of insolvency, plan participants will be general, unsecured creditors of the Company.

a.) and b.) See STF 5.72 (Retirement & Incentive Plan Expense). provided on the enclosed CD, for the cost of any SERP or similar programs and for the cost, by program, of each retirement program directly charged or allocated. The excel file on the enclosed CD is not identified by Bates numbers.

RESPONDEST: Human Resources Services Group

WITNESS: Dallas Dukes

UNS Gas, Inc.
Retirement & Incentive Plan Expense-2005
For the year ended 12/31/05
In response to STF 5.72a and 5.72b

Plan	2005 Expense per UNSG G/L
UES Plans:	
UES Pension Plan	$ 774,997
UES 401K Plan	$ 165,519
UES PEP Plan	$ 133,834
Other Plans:	
SERP Plan	$ 93,075
Long-Term Incentive Plan	$ 108,920
PEP Plan	$ 52,860
Deferred Comp Plan	$ 11,315
Omnibus Plan	$ 38,342
	$ 1,378,862

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 18,2007

STF 11.5 Incentive Compensation. Refer to the response to RUCO 6.10.

a. Show in detail the 2004 and 2005 PEP financial performance goals and the actual results.

b. Show in detail how the Special Recognition Award in 2005 was determined.

c. Provide the PEP in effect during each year, 2004, 2005 and 2006.

RESPONSE:

a. Please see STF 11.5(a), Bates Nos. UNSG(0463)05831 to UNSG(0463)05832, on the enclosed CD for the 2004 and 2005 UNS Gas, Inc. ("UNS Gas") portion of PEP which includes financial performance goals and actual results. STF 11.5(a) contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

b. UNS Gas is in the process of gathering this information and will provide it shortly.

c. UNS Gas is in the process of gathering this information and will provide it shortly.

SUPPLEMENTAL RESPONSE:

a. UNS Gas' response to STF 11.5 (a) was provided to Staff on January 9, 2007.

b. As previously stated, the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Gas and Tucson Electric Power Company ("TEP"), was not met. The financial performance was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Award was paid at approximately 42% of the target for each of the three operating companies.

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 18,2007

c. In 2004, the UniSource Energy Services, Inc. ("UES") PEP goal was separate from that of TEP. It had two primary goals: a financial goal specific to UES (UNS Gas and UNS Electric combined) and a set of goals measuring UNS Gas expense management, customer service, system reliability, and safety. Each of the two primary goals was weighted equally; however, PEP only paid if the primary financial goal was met. The primary UES financial goal was met in 2004.

In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Gas financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in response to STF 11.5 b, the 2005 primary financial goal was not met.

In 2006, the PEP structure was changed to the existing program today. It consists of three independent primary goals, and each of the primary goals has its own trigger, meaning that if one of the primary goals is not met, there is opportunity to still achieve on the two remaining primary goals. The three primary goals are comprised of a UniSource Energy Corporation Earnings per Shars goal (weighted 30%), a Cost Containment goal which manages Operations and Maintenance spending (weighted 30%), and Core Business and Customer Service goals (weighted 40%). The Core Business and Customer Service goals have many sub-goals beneath them, measuring reliability, customer service, project completion, regulatory and safety.

RESPONDENT: Michael Daranyi

WITNESS: Dallas Dukes

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

STF 5.91	Legal Expense. Please itemize the amount of non-rate case legal expense for the test year. For each distinct item over $20,000, show payee, amount, account, and indicate what services were performed and what the subject matter of the services was.
RESPONSE:	STF 5.91, provided on the enclosed CD, is a worksheet in excel format which itemizes the amount of non-rate case legal expense for the test year. The Excel file is not identified by Bates numbers.
RESPONDENT:	Regulatory Services Department
WITNESS:	Dallas Dukes

UNS Gas, Inc.
Legal Invoice Query
2005

GL Date	Account	Amount	Payee/Vendor Name	Subject Matter	Service Performed
JAN-05	52010	18.00	ROSHKA DEWULF & PATTEN PLC		
JAN-05	52010	200.00	MARY L BONILLA		
JAN-05	52010	307.13	LEWIS AND ROCA LLP		
JAN-05	52010	600.00	THELEN REID & PRIEST LLP		
JAN-05	52010	6,248.77	FLEISCHMAN & WALSH LLP		
JAN-05	52010	19,216.41	LEWIS AND ROCA LLP		
MAR-05	52010	89.34	LEWIS AND ROCA LLP		
MAR-05	52010	252.00	ROSHKA DEWULF & PATTEN PLC		
MAR-05	52010	386.00	ROSHKA DEWULF & PATTEN PLC		
MAR-05	52010	563.40	ROSHKA DEWULF & PATTEN PLC		
MAR-05	52010	19,887.55	FLEISCHMAN & WALSH LLP		
APR-05	52010	111.35	LEWIS AND ROCA LLP		
APR-05	52010	180.00	ROSHKA DEWULF & PATTEN PLC		
APR-05	52010	11,201.01	ROSHKA DEWULF & PATTEN PLC		
APR-05	52010	19,083.78	FLEISCHMAN & WALSH LLP		
APR-05	52010	19,482.02	FLEISCHMAN & WALSH LLP		
MAY-05	52010	87,268.56	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
JUN-05	52010	(720.00)	THELEN REID & PRIEST LLP		
JUN-05	52010	133.75	LEWIS AND ROCA LLP		
JUN-05	52010	2,490.20	ROSHKA DEWULF & PATTEN PLC		
JUN-05	52010	11,030.00	FLEISCHMAN & WALSH LLP		
JUN-05	52010	11,234.83	ROSHKA DEWULF & PATTEN PLC		
JUL-05	52010	3.75	THELEN REID & PRIEST LLP		
JUL-05	52010	216.00	ROSHKA DEWULF & PATTEN PLC		
JUL-05	52010	360.00	ROSHKA DEWULF & PATTEN PLC		
JUL-05	52010	14,299.22	FLEISCHMAN & WALSH LLP		
AUG-05	52010	28,463.40	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
SEP-05	52010	40.80	LEWIS AND ROCA LLP		
SEP-05	52010	56,611.88	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
OCT-05	52010	297.80	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	313.61	LEWIS AND ROCA LLP		
OCT-05	52010	462.00	BOULEY SCHIESINGER & SCHIPPERS		
OCT-05	52010	1,928.24	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	2,304.50	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	3,411.86	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	32,330.68	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
NOV-05	52010	396.00	ROSHKA DEWULF & PATTEN PLC		
NOV-05	52010	15,277.45	ROSHKA DEWULF & PATTEN PLC		
NOV-05	52010	28,712.29	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
DEC-05	52010	17,612.56	ROSHKA DEWULF & PATTEN PLC		
DEC-05	52010	39,128.51	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
DEC-05	52010	139.20	LEWIS AND ROCA LLP		
DEC-05	52010	228.00	BOULEY SCHIESINGER & SCHIPPERS		
DEC-05	52010	1,662.40	ROSHKA DEWULF & PATTEN PLC		
DEC-05	52010	25,452.58	ROSHKA DEWULF & PATTEN PLC	Professional Research and filing services	Prudency Audit/PGA Surcharge/Broderick Complaint
DEC-05	52010	38,534.74	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case

517,451.57	Total legal expense
(311,050.06)	Rate case settlement negotiations
206,401.51	Difference

UNS GAS, INC.'S RESPONSES TO
RUCO'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 21,2006

6.09 Pro Forma Adiustment – Worker's Compensation Expense – Please provide additional back-up information to explain why the Company is treating this expense in a similar manner as post employment benefits when worker's compensation is related to active employees only.

RESPONSE: The Worker's Compensation expense is recorded under Statement of Financial Accounting Standards No. 112, ***Employers' Accounting for Postemployment Benefits*** ("FAS 112"). FAS 112 specifically states that postemployment benefits are all types of benefits provided to former or inactive employees and worker's compensation is included as a postemployment benefit. Please see RUCO 6.09, Bates No. UNSG(0463)05610, on the enclosed CD for the summary portion of FAS 112 copied from the Financial Accounting Standards Board Original Pronouncements as Amended 200512006 Edition.

RESPONDENT: Ann Eckert

WITNESS: Dallas Dukes

Statement of Financial Accounting Standards No. 112
Employers' Accounting for Postemployment Benefits

an amendment of FASB Statements No. 5 and 43

STATUS

Issued: November 1992

Effective Date: For fiscal years beginning after December 15, 1993

Affects: Amends FAS 5, paragraph 7
Amends FAS 43, paragraph 1
Replaces FAS 43, paragraph 2
Amends FAS 107, paragraph 8(a)

Affected by: Paragraph 5(d) amended by FAS 123, paragraph 391 and FAS 123(R), paragraph D5
Paragraph 9 amended by FAS 123, paragraph 387; FAS 123(R), paragraph D5; and FAS 144, paragraph C8

AICPA Accounting Standards Executive Committee (AcSEC)

Related Pronouncement: SOP 94-6

Issues Discussed by FASB Emerging Issues Task Force (EITF)

Affects: No EITF Issues

Interpreted by: No EITF Issues

Related Issue: EITF Issue No. 96-5

SUMMARY

This Statement establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (referred to in this Statement as *postemployment benefits*). Postemployment benefits are all types of benefits provided to former or inactive employees, their beneficiaries, and covered dependents. Those benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage.

This Statement requires employers to recognize the obligation to provide postemployment benefits in accordance with FASB Statement No. 43, *Accounting for Compensated Absences*, if the obligation is attributable to employees' services already rendered, employees' rights to those benefits accumulate or vest, payment of the benefits is probable, and the amount of the benefits can be reasonably estimated. If those four conditions are not met, the employer should account for postemployment benefits when it is probable that a liability has been incurred and the amount can be reasonably estimated in accordance with FASB Statement No. 5, *Accounting for Contingencies*. If an obligation for postemployment benefits is not accrued in accordance with Statements 5 or 43 only because the amount cannot be reasonably estimated, the financial statements shall disclose that fact.

This Statement is effective for fiscal years beginning after December 15, 1993.

**UNS GAS, INC.'S RESPONSES TO
RUCO'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 21,2006**

6.06 Pro Forma Adjustment – Worker's Compensation Expense – Please provide additional back-up information, which verifies the Commission's historical treatment of this specific expense is required to be recorded on a cash basis.

RESPONSE: UNS Gas does not have this additional back-up information.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS, INC.'S RESPONSE TO
STAFF'S SIXTEENTH SET OF DATA REQUESTS
Docket No. G-04202A-06-0463
January 22,2007

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

STF 16.1 AGA Dues. Refer to the response to STF 5.62.

a. Please provide the invoices and all correspondence accompanying such invoices for the $41,854 in payments to the AGA mentioned in response to STF 5.62.

b. If different, please also provide the invoices and related correspondence for the total amount of AGA dues UNS Gas recorded during the test year, including an identification of any portions of AGA dues that UNS Gas recorded in below-the-line accounts.

c. Does UNS Gas participate in AGA's "Voluntary Ad Campaign?" If so, please identify all cost related to such participation, by amount and account, for the test year.

d. Does UNS Gas participate in or provide funding for any AGA advertising or marketing programs? If so, please identify all cost related to such participation, by amount and account, for the test year.

e. Please identify and provide the cost associated with all AGA advertisements used during the test year by UNS Gas.

f. Does UNS Gas agree that the NARUC sponsored audit reports on the expenditures of the American Gas Association provide the best information concerning AGA expenditures by category for use by utility regulatory commissions in evaluating which, if any, of the costs of that association should be included in utility rates? If not, please provide all information that UNS Gas believes is a better source for this purpose than the NARUC sponsored audit reports on the expenditures of the American Gas Association.

RESPONSE:

a. Please see STF 16.1 (a), Bates Nos. UNSG(0463)05908 to UNSG(0463)05910, on the enclosed CD for the supporting documentation for the $41,854 payment to AGA.

b. The $41,854 is the total amount paid to AGA during the test year.

**UNS GAS, INC.'S RESPONSE TO
STAFF'S SIXTEENTH SET OF DATA REQUESTS
Docket No. G-04202A-06-0463
January 22,2007**

c. UNS Gas did not participate in the AGA's "Voluntary Ad Campaign."

d. UNS Gas did not participate or provide funding for any AGA advertising or marketing programs.

e. UNS Gas had no cost associated with AGA advertisements.

f. UNS Gas has not reviewed the NARUC sponsored audit report of the AGA and presently has no opinion on the relevance of such a report.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UniSourceEnergy
SERVICES

FACSIMILE TRANSMITTAL SHEET

TO: Jessica Graham	FROM: Jennifer Wyraske
COMPANY: TEP	DATE: 1-31-05
FAX NUMBER: 520-571-4118	TOTAL NO. OF PAGES INCLUDING COVER: 3
PHONE NUMBER: 520-745-3127	SENDER'S REFERENCE NUMBER:
RE:	YOUR REFERENCE NUMBER

☐ URGENT ☐ FOR REVIEW ☐ PLEASE COMMENT ☐ PLEASE REPLY ☐ PLEASE RECYCLE

NOTES/COMMENTS:

2901 W. SHAMRELL BOULEVARD, SUITE 110, FLAGSTAFF, ARIZONA 86001
PHONE: 928-226-2184 FAX: 928-779-5338

Voucher Request for Check, EFT or Wire Transfer

☐ Check ☐ EFT ☐ Wire Transfer

COMPANY SELECTION: (Check a box)

☐ Millennium Energy Holdings (MEHC)
☐ Millennium Environ Group (MEG)
☐ Tucson Electric Power (TEP)
☐ Other (specify) ______

☐ UniSource Energy Corporation (UNS)
☐ UNS Electric (UNE)
☒ UNS Gas (UNG)

VENDOR#: ______ POW ______

DUE DATE: ______ INVOICE#: ______ AMOUNT: $41854

PAY TO THE ORDER OF: American Gas Association

ADDRESS: PO Box 79226

CITY/STATE/ZIP: Baltimore Maryland 21279-0226

EXPLANATION/BUSINESS PURPOSE: Membership Dues

☐ Mail Check
☒ Return check to. Roxi Ashurst Mail stop: FLAG-G Ext. 2184

Requested by (Please Print): Jennifer Wytaske Signature: Jennifer Wytaske ______ Date 01-28-2005

For Immediate Pay Only, this voucher must be manually approved

Approved by (Please Print): G.A. Smith ______ Signature: G. A. Smith ______ Date 31 Jan 2005

FOR WIRE TRANSFERS ONLY: Vendor's bank routing information must be supported with a letter from the vendor or the bank routing information must be on the vendor's invoice.

RECEIVED

Bank Name: ______

ABA (routing number) ______ Account ______

JAN 31 2005

ACCOUNTS PAYABLE

MATERIALS >$ 2,500: need Procurement & Contracts Dept Approval.

Apvd. by (Please Print) ______ Signature: ______ Date ______

ACCOUNTING INFORMATION:

Project	Task	Expenditure Type	Expenditure Org (Cost Center)	Amount	
UNSG050	G500930	Member Dues - Corporate	UNSG Arizona Gas Admin	41854	00

Account Alias or G/L Account String - if applicable	Amount	

Note: Projects can not start with an A & Expenditure Types can not start with a 9. If you need accounting information, contact Amber Young in Financial Reporting at 745-3164. Amber will provide you with the information to put in the following box:

Form 5011 rev 12/04

AGA
American Gas Association
Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

2005 DUES

Year ending December 31, 2005

Full Member Company X   Limited Member Company ____

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2001 ____* 2002 4,500 2003 4,128 Average ____

YOUR 2004 DUES WERE .... $ 20,927 1

YOUR 2005 DUES ARE .... $ 41,854 2

1. Dues phase-in amount. 2004 represents one-half of full does of $41,854.
2. Phase-in to full dues.

2005 Payment Schedule

____ Full amount enclosed   ____ Semi-annually (Jan.1, July 1)

____ Quarterly (Jan.1, Apr.1, July 1, Oct.1)   ____ Other (Please state)

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to *the* address noted above.

Invoice to: ....   Approved: ....

....   Title: ....

....   Date: ....

Phone: ( ) .... - ....   Fax ( ) .... - ....

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. The Association will pay directly the federal tax that is due on lobbying activities.

Dues include a one-year subscription to *American Gas*, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8, 2006**

STF 5.28 For each plant account, please provide the actual cost of removal and net salvage information for each year, 2000 through 2005.

RESPONSE: The assets of UNS Gas were acquired from Citizens Communications Company ("Citizens") on August 11, 2003. Cost of removal and salvage data for periods prior to that date are not available. See STF 5.28, provided on the enclosed CD, for the accompanying schedule showing the actual annual cost of removal and salvage transactions recorded by FERC Account subsequent to that acquisition. The Excel file on the CD is <u>not</u> identified by Bates numbers.

Also, see the response to STF 5.6.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger

UNS Gas, Inc.
Actual Cost of Removal and Proceeds of Sale

Plant Account	Description	Category	Year	Cost of Removal	Proceeds of Sale
	No Activity		2003	-	-
				-	-
	No Activity		2004	-	-
				-	-
376	Mains	01.376XX.051.00000.000	2005	160.00	-
376	Mains	01.376XX.053.00000.000	2005	3,375.10	
392	Transportation Equipment	01.392C1.051.00000.000	2005	-	10,607.00
392	Transportation Equipment	01.392C1.052.00000.000	2005	-	5,500.00
392	Transportation Equipment	01.392C1.053.00000.000	2005	-	1,601.50
392	Transportation Equipment	01.392C2.050.00000.000	2005	-	23,957.60
392	Transportation Equipment	01.392C2.051.00000.000	2005	-	54,948.86
392	Transportation Equipment	01.392C2.052.00000.000	2005	-	43,233.00
392	Transportation Equipment	01.392C2.053.00000.000	2005	-	1,500.00
392	Transportation Equipment	01.392C2.055.00000.000	2005	-	1,403.14
392	Transportation Equipment	01.392C2.056.00000.000	2005	-	36,124.00
392	Transportation Equipment	01.392C3.050.00000.000	2005	-	19,290.00
392	Transportation Equipment	01.392C3.051.00000.000	2005	-	8,400.00
392	Transportation Equipment	01.392C3.053.00000.000	2005	-	2,000.00
392	Transportation Equipment	01.392C3.056.00000.000	2005	-	3,113.16
392	Transportation Equipment	01.392C4.056.00000.000	2005	-	1,386.84
				3,535.10	213,065.10

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.2 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b:

a. Please provide all cost studies and economic analysis that the Company has relating to its proposed increase in reimbursement from the customer to the Company for gas service line from $8 to $16 per foot.

b. Please provide all cost studies and economic analysis that the Company has relating to its proposed increase to $12 per foot for customers who provide the trench for the service line on their own property.

c. Please provide the complete documentation and calculations relied upon by the Company for its $16 per foot current costs (Smith, page 19, line 7-8) and $12 (Smith page 19, line 12).

d. Please identify for each year of UNS Gas ownership through 2006, the annual amount of customer reimbursement for gas service line connections, the annual cost incurred by UNS Gas for such connections, the amount of billings to customers for such connections, and the amount of feet installed.

RESPONSE: a. Please see STF 13.2 on the enclosed CD for all cost studies and the economic analysis the Company has relating to its proposed increase in reimbursement from the customer to the Company for a gas service line from $8 to $16 per foot. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

b. Please see STF 13.2 on the enclosed CD for all cost studies and economic analysis that the Company has relating to its proposed increase to $12 per foot for customers who provide the trench for the service line on their own property. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

c. Please see STF 13.2 on the enclosed CD for the complete documentation and calculations relied upon by the Company for its $16 per foot current costs (Smith, page 19, line 7-8) and $12 (Smith page 19, line 12). The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
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January 16, 2007

d. Please see STF 13.2 on the enclosed CD for UNS Gas ownership through 2006, the annual amount of customer reimbursement for gas service line connections, the annual cost incurred by UNS Gas for such connections, the amount of billings to customers for such connections, and the amount of feet installed. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.6 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. Please provide actual illustrative examples during 2006 for calculations prepared by the Company under the Incremental Contribution Study.

b. Please provide an illustrative example of calculations prepared pursuant to an Incremental Contribution Study, assuming the Company's proposed rates of reimbursement were to be approved.

RESPONSE:

a. Please see STF 13.6 on the enclosed CD for illustrative examples of calculations prepared by the Company under the Incremental Contribution Study during 2006. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

b. Please see STF 13.6 on the enclosed CD for an illustrative example of calculations prepared pursuant to an Incremental Contribution Study, assuming the Company's proposed rates of reimbursement were to be approved. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

**ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007**

STF 13.7 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. Please identify the number of customers the Company anticipates would be affected by this proposed change and the total annual impact on such customers in total and on average.

b. Include supporting calculations for your response to part a.

RESPONSE:

a. Please STF 13.7 on the enclosed CD for the number of customers the Company anticipates would be affected by the proposed change and the total annual impact on such customers in total and on average. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

b. Please see STF 13.7 on the enclosed CD for supporting calculations. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

**ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007**

STF 13.8 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 10.C:

a. Referring to page 19, lines 20-21, please identify the specific provisions of the Arizona Administrative Code that the Company is relying upon for its alignment proposal.

b. For each change in "billing terms" proposed by the Company, please clearly identify the current provision, the basis for the current provision (e.g., cite to a prior Commission order) and explain clearly how and why the new or revised provision is an improvement over the existing provision.

RESPONSE:

a. R14-2-310(c) is the specific provision of the Arizona Administrative Code ("AAC") that UNS Gas is referring to for its alignment proposal.

b. UNS Gas' proposed revisions to the "Billing Terms" section of the Rules and Regulations are identified in the Direct Testimony of Gary A. Smith as Exhibit GAS - 2. The current Rules and Regulations were approved by the Commission in Decision No. 66028 with the acquisition of Citizens Communications Company. The proposed revisions align UNS Gas' "Billing Terms" with those outlined in the AAC, eliminating any confusion customers may have between them. Additionally, the proposed revisions will ultimately align with TEP and UNS Electric (both UniSource Energy Companies), thereby minimizing confusion among UNS Gas and UNS Electric customers who are often the same individuals.

RESPONDENT: Regulatory Services Department

WITNESS: Gary Smith

**ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16,2007**

STF 13.9 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 10.C.

a. How do UNS Gas' proposed dues dates and time periods for late payment penalty charges compare with those currently in effect by other Arizona gas distribution utilities?

b. Please provide all comparative information the Company has with respect to how UNS Gas's proposed service line connection charges compare with those currently in effect by other Arizona gas distribution utilities.

c. How do UNS Gas' proposed dues dates and time periods for late payment penalty charges compare with those currently in effect by TEP and UNS Electric?

d. Please provide all comparative information the Company has with respect to how UNS Gas' proposed service line connection charges compare with those currently in effect by TEP and UNS Electric.

e. Please identify the annual amount of late payment penalty charge revenue for each year through 2006 under UNS Gas ownership.

f. Please identify the estimated annual impact on late penalty revenue if the Company's proposed time period for late penalty charges is implemented as proposed. Include supporting calculations showing in detail how such estimated annual impact was derived.

RESPONSE:

a. UNS Gas' proposed revisions to the due dates and time periods for late payment penalty charges were not made based on those of other Arizona gas distribution utilities, they were revised to follow the AAC R13-2-310. UNS Gas does not have the requested comparative information in its possession.

b. UNS Gas did not use comparative information when it determined and proposed its new Line Extension Tariff. UNS Gas does not have the requested comparative information in its possession.

c. TEP's current due date and time periods for late payment penalty charges are the same as those proposed by UNS Gas. Proposed

**ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
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January 16,2007**

revisions to UNS Electric's Rules and Regulations were filed on December 15, 2006. The proposed UNS Electric revisions match those of UNS Gas and TEP. Although UNS Gas did not use this information, the requested comparative information is as follows: TEP makes overhead distribution line extensions at no cost to the customer up to five (500) feet. Extensions in excess of five hundred (500) feet are computed at a rate of five dollars ($5.00) per foot for each foot of single phase line extension or eight dollars ($8.00) per foot for each foot of three phase line extension in excess of the free extension length. UNS Electric will extend single phase overhead distribution facilities without charge to customers provided that the length of the extension does not exceed four hundred (400) feet. Extensions in excess of four hundred (100) feet are provided based on an economic feasibility study and that such extension does not exceed a total construction cost of $25,000.

d. UNS Gas did not use comparative information from other Arizona Utilities with respect to its proposed revisions to the service line connection charge.

e. UNS Gas late payment revenue charged to FERC 487 was as follows:

2003 = $79,699
2004 = $381,781
2005 = $398,966
2006 = $524,050

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f. The Company is not able to estimate the impact the proposed change in time period may have on late payment revenue collections.

RESPONDENTS: Regulatory Services Department (a, b, c and d)
Amy Teller (e)
Jean Dannen (f)

WITNESS: Gary Smith

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STF 13.10 Refer to Section 10.J, Electronic Billing.

a. How does UNS Gas' proposed provision for electronic billing compare with provisions of other regulated Arizona utilities concerning electronic billing? Please provide all comparative information the Company has with respect to how UNS Gas' proposed provision for electronic billing compares with those of other Arizona utilities.

b. Does TEP or UNS Electric currently have a provision for electronic billing? If so, please provide a copy of those provisions.

c. If TEP or UNS Electric currently has a provision for electronic billing, please identify the number of customers, by year. that utilize electronic billing, through 2006.

d. Does UNS Gas anticipate any savings (e.g., postage, bill printing, etc.) from electronic billing? If so, please identify, quantify and explain the annual savings anticipated from electronic billing.

RESPONSE:

a. UNS Gas' proposed provision for electronic billing was based on TEP's electronic billing program. The new electronic billing program will have the same program capabilities once UNS Gas converts to its new customer information system. The Company did not make comparisons with other regulated Arizona utilities concerning electronic billing.

b. TEP e-bill began in May of 2003. UNS Electric launched e-bill in January 2006. For both Companies, customers can sign up for e-bill via telephone or the company web site. Customers are notified via email that their bill is ready to view.

c. TEP customers utilizing e-bill:

December 2003 - 13,879 customers
December 2004 - 33,120 customers
December 2005 - 50,383 customers
December 2006 - 67,765 customers

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UNS Electric customers utilizing e-bill:

December 2006 -1,773 customers

d. The Company estimates that during the test year it realized savings in postage, bill stock, mailing envelopes and remittance envelopes of approximately $4,000.

RESPONDENT: Regulatory Services Department (a)
Jean Dannen (b, c and d)

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
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STF 13.11 Refer to Gary Smith's testimony at page 20 and Section 11.E.

a. Please identify the specific provisions of the Arizona Administrative Code that the Company is relying upon for its alignment proposal.

b. How many termination notices has UNS Gas issued to customers in each year through 2006 under its ownership of the gas system?

c. How many terminations has UNS Gas conducted in each year through 2006?

d. Does the Company have any studies or information concerning whether cutting the termination notice from 10 days to 5 days would present a hardship for customers? If so, please identify, explain and provide all such information.

e. Concerning the provision in 11.E.2:

i. From what location(s) does UNS Gas mail its termination notices?

ii. What is the approximate average time for delivery of first class mail to customers when mailed from the location(s) identified in response to the above request?

f. Please clarify whether the 10 days current provision and the 5 days proposed provision for termination notice in 11.E.1 are calendar days or business days.

g. Do any other Arizona utilities have a termination notice period less than 10 days? If so, please identify them.

h. Please identify the utility service termination notice period for each Arizona utility of which UNS Gas is aware.

RESPONSE: a. R14-2-311 (E)(1) is the specific provision of the AAC that the Company is referring to for its alignment proposal.

b. Following are the number of Suspension of Gas Service Notices mailed to customers:

**ARIZONA CORPORATION COMMISSION
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28, 631 from August 11,2003 through December 31,2003

108,639 for Calendar year 2004 (Moratorium on mailing notices March 13, 2004 though April 18,2004)

106,407 for Calendar year 2005 (Moratorium on mailing notices November 21,2005 through December 31,2005)

101,382 for Calendar year 2006 (Moratorium on mailing notices January 1,2006 through March 31,2006)

c. Following are the number of terminations UNS Gas conducted:

1,281 from August 11,2003 through December 31,2003

3,942 for calendar year 2004 (Moratorium on disconnects from February 19,2004 through April 29,2004)

4,495 for calendar year 2005 (Moratorium on disconnects from December 1,2005 through December 31,2005)

3,445 for calendar year 2006 (Moratorium on disconnects from January 1, 2006 through March 31,2006)

d. The Company does not have study information. The five days provision is based on A.A.C. R14-2-311(E)(1). UNS Gas assumes that the Commission would not adopt a rule that would result in undue hardship for customers.

e. Concerning the provision in 11.E.2:

i. With the conversion to the new customer care and billing system (currently scheduled for April 2, 2007), notices will be mailed from Tucson Arizona.

ii. Approximate average time for delivery of first class mail is 2 days

f. The current ten-day provision is calendar days and the five-day proposed revision will be calendar days. The five-day provision in

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the Arizona Administrative Code (A.A.C. R14-2-311 (E)(1)) is also five calendar days. See A.A.C. R14-3-301(16).

g. TEP and UNS Electric currently match the AAC's five (5) day advance notice provision. The Company did not compare its proposed revision to any other Arizona Utilities.

h. Please see the response to STF 13.11 (g) above.

RESPONDENT: Regulatory Services Department (a, g and h)

WITNESS: Gary Smith

UNS GAS, INC.'S RESPONSES TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
SEPTEMBER 11,'2006

1.10 Rate Filing Please provide an electronic copy of the rate filing schedules A-H and all supporting workpapers, with all formulas intact.

RESPONSE: Electronic copies of the rate filing Schedules A-H and all supporting workpapers are provided on the attached CD as RUCO 1.10.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESSES: Karen Kissinger and Dallas Dukes

UNS GAS
Cash Working Capital - LeadILag Study
For the Test Year EndIng 12131105

Descrption	FERC	Pro Forma Test Year Amount		Revenue Lag Days		Lxpense Lag Days		Net Lag Days (Col. C - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.B)
(A)		(B)		(C)		(D)		(E)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 722,634	1a							$
Depreciation	403/404	7,950,183	1.4a							
Amortization	406	(729,791)	1.4b							
Deferred Income Taxes		3,178,719								
Other Operating Expenses -										
Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	38.95	C.	24.50	E.	14.45	0.0396	288,595
Incentive Pay (UNSG Direct Employees)	Multi	257,895	3a	38.95	C.	267.00	F.	(228.05)	(0.6248)	(161,133)
Purchased Gas	Calc	78,101,248	4a	38.95	C.	30.97	D.	7.98	0.0219	1,711,508
Office Supplies and Expenses	921	1,365,974	1.2a	38.95	C.	20.72	H.	18.23	0.0499	68,162
Injuries and Damages	925	574,128	1.2b	38.95	C.	64.75	H.	(25.80)	(0.0707)	(40,591)
Pensions and Benefits	926	2,452,071	1.2c	38.95	C.	54.66	H.	(15.71)	(0.0430)	(105,439)
Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A.	4,570,692	6a	38.95	C.	44.91	G.	(5.96)	(0.0163)	(74,502)
Property Taxes	408	4,103,376	1.4c	38.95	C.	213.00	I.	(174.05)	(0.4768)	(1,956,490)
Payroll Taxes	408	537,877	1.4d	38.95	C.	19.30	I.	19.65	0.0538	28,938
Current Income Taxes		(1,203,222)		38.95	C.	41.42	I.	(2.47)	(0.0068)	8,182
Interest on Customer Deposits	431	170,459	1.4e	38.95	C.	182.50	J.	(143.55)	(0.3933)	(67,042)
Other Operations and Maintenance	Multi	7,501,807	X.	38.95	C.	53.10	K.	(14.15)	(0.0388)	(291,070)
Total Operating Expenses		116,841,794								
Other Cash Working Capital Elements:										
Interest on Long-Term Debt		5,334,825		38.95	C.	91.62	J.	(52.67)	(0.1443)	(769,815)
Revenue Taxes and Assessments	Calc	$ 18,788,535	L.	38.95	C.	76.25	I.	(37.30)	(0.1022)	(1,920,188)
Total Cash Working Capital										$ (3,280,886)

ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas LeadILag Only	78,101,248	4a
ProForma Oper. Exp. To Tie Too - Excl Income Taxes	114,866,298	
Less: 1a, 1.4a, 1.4b, 2a, 3a, 4a, 1.2a, 1.2b, 1.2c, 6a, 1.4c, 1.4d, 1.4e	107,364,490	
Other O&M	$ 7,501,807	X.

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

STF 5.36 Refer to Schedule E-1. Please provide the detailed components of the Accumulated Deferred Income Taxes amounts under Regulatory and Other Assets and under Deferred Credits and Other Liabilities, as of 12/31/05 and 12131/04.

RESPONSE: The ADIT appearing on Schedule E-1 is reported in accordance with Statement of Financial Accounting Standards No. 109 and reflects the tax effect of <u>all recorded</u> book-tax temporary differences, both operating and non-operating, that will reverse in the future. The net balances of $9.2 million and $6.1 million for December 31, 2005 and December 31, 2004, respectively, reflect future income tax liabilities that will come due when the differences reverse over time. See STF 5.36 on the enclosed CD for a summary of the components of the recorded balances. The Excel file on the CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Carl W. Dabelstein

WITNESS: Karen Kissinger

Response to Staff D.R. 5.36
Per Books A.D.I.T. at 12/31/05

Timing Difference Description	A.D.I.T. at 12/31/05 Dr (Cr)	A.D.I.T. at 12/31/04 Dr (Cr)
Acct. 190 - Deferred Tax Assets		
Bad Debts Expense	132,013	174,332
Incentive Comp. - PEP	27,840	170,779
Interest Expense - Audit	10,950	-
Vacation Accrual - Book	94,651	32,260
Customer Advances in Aid of Construction	2,930,929	1,430,875
Dividend Equivalents	31,324	8,754
FAS 112 - Book	26,876	40,433
Long Term Incentive Comp.	100,975	91,838
Restricted Stock - Directors	20,121	15,828
Supplemental Executive Retirement Plan	88,747	-
Contributions in Aid of Construction	1,420,670	736,832
AMT - Credit	(189,102)	-
Pension Adjustment	-	19,799
Total Deferred Tax Assets	4,695,994	2,721,730
Acct. 282 A.D.I.T.		
Capitalized A&G	(343,587)	(29,994)
AFDC - Equity	(79,479)	(19,051)
Depreciation	(9,944,995)	(6,480,187)
Capitalized Repairs	(255,053)	
Acquisition Adjustment	(212,729)	
	(10,835,843)	(6,529,232)
Acct. 283 A.D.I.T.		
Purcnased Gas Bank	(2,336,159)	(737,464)
Capiralized A&G	(443,036)	(1,289,636)
AFDC-Equity	(97,974)	(83,667)
CARES Program Expenses	(43,219)	-
Pensions Liability	(154,911)	(126,514)
Repairs Capitalized	(77,553)	(63,518)
	(3,152,852)	(2,300,799)
Total Deferred Tax Liabilities	(13,988,695)	(8,830,031)
Net Deferred Tax Liability	(9,292,701)	(6,108,301)

**UNS GAS, INC.'S RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 9,2007**

STF 11.10 Please provide the number of customers, by rate class, by month, for the test year and for months subsequent to the test year.

RESPONSE: For the number of customers, by rate class, by month, for the test year and for months subsequent to the test year, please see STF 11.10 provided on the enclosed CD. The Excel file on the CD is not identified by Bates numbers.

RESPONDENT: Brenda Pries

WITNESS: Tobin Voge

UNS GAS INC TOTAL RETAIL CUSTOMERS

	JAN45	FEB-05	MAR 05	APR 05	MAY 05	JUN-05	JUL-05	AUG-05	SEP-05	OCT-05	NOV-05	DEC-05	Jan-06	Feb 06	Mar-06	Apr-06	May06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06
Retail Customers																							
Residential:																							
5751 Res RIR10	117,503	117,602	118,537	118,170	118,084	118,566	118,318	118,974	119,000	119,735	120,289	121,125	122,128	122,416	123,191	123,342	123822	124,143	123,746	124,723	124,379	124,924	125,893
5752 Res CARES RIR12	4,798	4,905	5,015	5,161	5,275	5,358	5,407	5,443	5,377	5,341	5,484	5,556	5,670	5,754	5,930	5,994	5,929	5,845	5,789	5,736	5,811	5942	6,010
5763 Comprsd Nat Gar RICNG1			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
Total Residential Customers	122,301	122,507	123,553	123,332	123,360	123,925	123,726	124,418	124,378	125,077	125774	126,682	127,799	128171	129,128	129337	129,752	129,989	129,536	130,461	130,192	130,866	131,935
Commercial																							
5753 Sm Vol Com Svc RIC20	10,877	10,891	10,974	10,960	10,902	10,816	10,772	10,730	10,701	10,728	10,821	11,017	11,149	11,161	11,234	11,228	11,226	11,097	11,037	11,051	11,026	11,125	11,283
5754 Lrg Vol Com Svc RIC22	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	10	11	11	11
5755 Irrigation Svc RIR80	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	5	5	5	5	6	5	5
5763 Comprsd Nat Gar RICNG1	0		0													1	1			1			
Total Commercial Customers	10,893	10,907	10,990	10,976	10,918	10,832	10,788	10,746	10,717	10,745	10,838	11,034	11,166	11,178	11,250	11,245	11,243	11,113	11,053	11,067	11,042	11,141	11,299
Industrial:																							
5758 Sm Vol Ind Svc RII30	13	13	13	13	12	13	12	13	13	13	12	12	12	11	12	13	13	13	13	13	13	13	12
5759 Lrg Vol Ind Svc RII32	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	7	7	7	7	7	7	7
Total Industrial Customers	20	20	20	20	19	20	19	20	20	20	19	19	19	18	19	19	20	20	20	20	20	20	19
Public Streets & Highway Lighting:																							
5764 Special Gas Light Svc RIP	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Public Streets & Highway Lighting	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Other Sales - Public Authorities:																							
5763 Comprsd Nat Gas RICNG1	5	5	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4	4	6	7	7	7
5765 Sm Vol Pub Auth Svc RIPA4	1,027	1,033	1,039	1,044	1,044	1,043	1,041	1,046	1,042	1,039	1,060	1,061	1,059	1,056	1,063	1,064	1,060	1,053	1,053	1,051	1,053	1,054	1,058
5766 Lrg Vol Pub Auth SK RIPA	6	6	6	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5
Other Sales - Public Authorities	1,038	1,044	1,049	1,054	1,054	1,053	1,051	1,056	1,052	1,049	1,059	1,059	1,068	1,065	1,072	1,073	1,069	1,062	1,062	1,061	1,065	1,066	1,070
T1 Transportation																							
Transportation Commercial	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	8	8	8	8	8	8	9	9
Transportation Industrial	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Transporation Public Authority	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	21	21	21	21	21	21	22	22
T2 Transportation																							
Transportation Industrial	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
NSP Customers																							
Commercial	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Industrial	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Public Authority	2	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1
	14	13	13	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13	13
TOTAL RETAIL CUSTOMERS	134,292	131.517	135,651	135422	135,391	135,870	135 624	136260	136.207	136,931	137730	138.833	140.091	140471	141.508	141,712	142,122	142,222	141,709	142.647	142.357	143.134	144,332

R14-2-102. Treatment of depreciation

A. The following definitions shall apply in this Section unless the context otherwise requires:

1. "Accumulated depreciation" means the summation of the annual provision for depreciation from the time that the asset is first devoted to public service.
2. "Cost of removal" means the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto.
3. "Depreciation" means an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life.
4. "Depreciation rate" means the percentage rate applied to the original cost of an asset to yield the annual provision for depreciation.
5. "Net salvage" means the salvage value of property retired less the cost of removal.
6. "Original cost" means the cost of property at the time it was first devoted to public service.
7. "Property retired" means assets which have been removed, sold, abandoned, destroyed, or which for any cause have been withdrawn from service and books of account.
8. "Salvage value" means the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.
9. "Service life" means the period between the date an asset is first devoted to public service and the date of its retirement from service.

B. All public service corporations shall maintain adequate accounts and records related to depreciation practices, subject to the following:

1. Annual depreciation accruals shall be recorded.
2. A separate reserve for each account or functional account shall be maintained.
3. The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant.
4. Public service corporations having less than $250,000 in annual revenue shall not be required to maintain depreciation records by separate accounts but shall make annual composite accruals to accumulated depreciation for total depreciable plant.

C. Requests for depreciation rate changes and methods for estimating depreciation rates shall be as follows:

1. If a public service corporation seeks a change in its depreciation rates, it shall submit a request for such as part of a rate application in accordance with the requirements of R14-2-103.
2. A public service corporation may propose any reasonable method for estimating service lives, salvage values, and cost of removal. The method shall be fully described in a request to change depreciation rates.
3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

EXHIBIT

ALL-STATE LEGAL®

S-26
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERTATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	DOCKET NO. G-04204A-06-01013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

SUPPLEMENTAL

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

CONCERNING RATE DESIGN AND BILL IMPACT ANALYSIS

FEBRUARY 23, 2007

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My supplemental testimony addresses the following issues:

- Staff's recommended rate design.
- Staff's bill impact analysis

My findings and recommendations for each of these areas are as follows:

- To achieve the recommended base rate increase of $4.962 million, Staff recommends the following rates:

Summary of Staff Recommended Rate Design			
Class of Service	**Current Rates**	**Proposed Rates**	***Change***
Residential Service (R10)			
Customer Charge	$ 7.00	$ 8.50	$ 1.50
Distribution Margin Therms	$ 0.3004	$ 0.3217	$ 0.0213
Residential Service Cares (R12)			
Customer Charge	$ 7.00	$ 7.00	$ -
Distribution Margin Therms	$ 0.3004	$ 0.3217	$ 0.0213
Winter Discount (up to 100 Therms)	$(0.1500)	$(0.1500)	$ -
Small Volume Commercial Service (C20)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2420	$ 0.2651	$ 0.0231
Large Volume Commercial Service (C22) and Commercial Transportation			
Customer Charge	$ 85.00	$ 100.00	$ 15.00
Distribution Margin Therms	$ 0.1551	$ 0.1731	$ 0.0180
Small Volume Industrial Service (I-30)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2122	$ 0.2369	$ 0.0247
Large Volume Industrial Service (I-32) and Industrial Transportation			
Customer Charge	$ 85.00	$ 100.00	$ 15.00
Distribution Margin Therms	$ 0.0864	$ 0.0965	$ 0.0101
Small Volume Public Authority (PA-40)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2354	$ 0.2606	$ 0.0252
Large Volume Public Authority (PA-42) and Public Authority Transportation			
Customer Charge	$ 85.00	$ 100.00	$ 15.00
Distribution Margin Therms	$ 0.1084	$ 0.1211	$ 0.0127
Special Gas Light Service (PA-44)			
Customer Charge Lighting Group A	$ 13.57	$ 15.17	$ 1.60
Customer Charge Lighting Group B	$ 16.28	$ 18.20	$ 1.92
Irrigation Service (IR-60)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2876	$ 0.3205	$ 0.0329

- Staff's bill impact analysis is shown in Attachment RCS-S2 to this testimony and shows the impact of Staff's proposed rate design for each rate class for a variety of monthly gas sales levels. The bill impact analysis is presented for total rates (including gas costs) and for base rates only.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of the supplemental testimony you are presenting?

A. The purpose of my supplemental testimony is to present Staff's proposed rate design and bill impact analysis. Another Staff witness, Mr. Steve Ruback, is addressing certain aspects of rate design, including his analysis of the rate design proposed by UNS Gas, Inc. ("UNS Gas").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-S1 shows Staff's recommended rate design and certain details regarding the development of the recommended rate design. Attachment RCS-S2 presents Staff's bill impact analysis, showing the impact of Staff's recommended rates over a variety of representative usage levels for customers in each customer class, for base rate impacts and total bill impacts[1], respectively.

[1] Staff is also recommending a DSM adjustor rate of $0.00082 per therm. This DSM adjustor rate has not been factored into the total bill impact analysis shown on Attachment RCS-S2.

II. RATE DESIGN

Q. Please discuss the factors which Staff considered in regard to rate design for UNS Gas.

A. Staff considered a number of factors in creating its rate design. These factors include cost of service, the desire to encourage energy conservation, the need to use gradualism in cases where rates are being charged so that customers are not hit by large rate increases, customer equity issues within and between rate classes, efforts to make rates and bills easier for customers to understand, revenue impacts on the Company, and other policy considerations. Given the number of various considerations which go into designing rates, some of which are not easily quantifiable, it is understandable why it is commonly said that rate design is more of an art than a science.

Q. What total margin target have you designed your proposed rates to meet?

A. The rates I am proposing are designed to provide a total margin to UNS Gas of $50.515 million. This represents a base rate revenue increase of $4.721 million over current revenues of $45.794 million.

Q. Please summarize the rate design that Staff recommends for UNS Gas to achieve this total margin.

A. The base rate design for UNS Gas that Staff recommends to produce this total margin is summarized in the following table:

Summary of Staff Recommended Rate Design			
Class of Service	**Current Rates**	**Proposed Rates**	**Change**
Residential Service (R10)			
Customer Charge	$ 7.00	$ 8.50	$ 1.50
Distribution Margin Therms	$ 0.3004	$ 0.3217	$ 0.0213
Residential Service Cares (R12)			
Customer Charge	$ 7.00	$ 7.00	$ -
Distribution Margin Therms	$ 0.3004	$ 0.3217	$ 0.0213
Winter Discount (up to 100 Therms)	$(0.1500)	$(0.1500)	$ -
Small Volume Commercial Service (C20)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2420	$ 0.2651	$ 0.0231
Large Volume Commercial Service (C22) and Commercial Transportation			
Customer Charge	$ 85.00	$ 100.00	$ 15.00
Distribution Margin Therms	$ 0.1551	$ 0.1731	$ 0.0180
Small Volume Industrial Service (I-30)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2122	$ 0.2369	$ 0.0247
Large Volume Industrial Service (I-32) and Industrial Transportation			
Customer Charge	$ 85.00	$ 100.00	$ 15.00
Distribution Margin Therms	$ 0.0864	$ 0.0965	$ 0.0101
Small Volume Public Authority (PA-40)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2354	$ 0.2606	$ 0.0252
Large Volume Public Authority (PA-42) and Public Authority Transportation			
Customer Charge	$ 85.00	$ 100.00	$ 15.00
Distribution Margin Therms	$ 0.1084	$ 0.1211	$ 0.0127
Special Gas Light Service (PA-44)			
Customer Charge Lighting Group A	$ 13.57	$ 15.17	$ 1.60
Customer Charge Lighting Group B	$ 16.28	$ 18.20	$ 1.92
Irrigation Service (IR-60)			
Customer Charge	$ 11.00	$ 13.50	$ 2.50
Distribution Margin Therms	$ 0.2876	$ 0.3205	$ 0.0329

Additional details of Staff's rate design proposals are contained in Attachment RCS-S1, which is appended to my supplemental testimony. Attachment RCS-S1 contains five schedules, labeled as Schedule RD-1 through RD-5, which show various calculations concerning the development of Staff's proposed rate design for UNS Gas in this proceeding.

Q. Please explain what is shown on Schedule RD-1 of Attachment RCS-S1.

A. Schedule RD-1 consists of two pages and shows the proof of revenue at current and Staff-proposed rates. Schedule RD-1, page 1, shows the proof of revenue at current rates using the billing units from UNS Gas' filing at Schedule H-2, page 1. Applying those billing units at current rates would produce base rate revenue of $45.449 million, as shown in Column C. This is approximately $240,000 below the adjusted book revenue from gas sales shown on UNS Gas' Schedule H-2, page 2 of 2, of $45.689 million, which is shown in Column D. The differences by rate class, which sum to $240,468, are shown in Column E. Columns F and G show the Staff adjustments to UNS Gas' proposed billing units that relate to the Staff customer annualization and weather normalization adjustments, respectively. Column H shows the Staff adjusted billing units, and Column I shows the revenues produced at current rates that result from the application of UNS Gas' current rates to those billing units. As shown on line 33, the difference of approximately $240,000 noted above occurs in Column I. The Staff adjusted average number of customers in each rate class is shown in Column J. Of particular importance to Staff's proposed rate design is the 5,556 number of Residential CARES (Rate R-12) customers.

Schedule RD-1, page 2, summarizes how the Staff's recommended rates provide UNS Gas with an opportunity to collect $50.515 million in base rate revenues, using the billing units from page 1. The Staff recommended customer charge and distribution margin per-therm rates for each rate class are shown in column D.

Q. What is shown on Schedule RD-2?

A. Schedule RD-2 shows the development of the CARES discount. As explained in the testimony of Julie McNeely-Kirwan, Staff recommends that the current $0.15 per therm discount for Residential CARES (Rate R-12) winter gas usage up to 100 therms per month be continued. Using 5,556 Residential CARES customers, the continuation of this discount at average monthly therms, provided by the Company in response to data request STF 15.3, produces the R-12 therm-based revenue discount of $320,006 shown on Schedule RD-2.

Q. Please explain Schedule RD-3.

A. Schedule RD-3 shows the development of Staff's recommended across-the-board base rate revenue increase of 11.80 percent, excluding the Residential CARES (Rate R-12) class. As shown on Schedule RD-3, Staff has calculated an across-the board increase for the rate classes other than Rate R-12, of approximately 11.80 percent.

Q. How does this compare with UNS Gas' rate design proposal?

A. As shown on Schedule H-1 of UNS Gas' filing, the Company has proposed net revenue increases for each class of service of approximately 21 percent. Staff's proposed net revenue increase of 11.80 percent for rate classes other than Residential CARES (R-12) is lower than the average 21.11 percent increases proposed by UNS Gas, which are summarized on Schedule H-1 and Schedule H-2, page 2, of the Company's filing. For the Residential CARES (R-12) rate, Staff proposes a revenue increase of approximately 4.54 percent. This is substantially lower than the 21.11 percent increase proposed by UNS Gas[2].

Q. What is shown on Schedule RD-4?

A. Schedule RD-4 shows an analysis of revenues generated by fixed charges under the current and Staff recommended rates. The Staff-recommended rate design reflects a gradual approach to increasing customer charges. As shown on Schedule RD-4, Staff's

[2] See Schedule H-2, page 2 of UNS Gas' filing.

recommended rate design reflects an equal or increased percentage of base rate revenue being collected via fixed charges. Of the $4.962 million[3] proposed base rate increase, the Staff recommended rate design collects approximately $2.560 million, or 52 percent of this increase, through fixed charges.

As shown on Schedule RD-4, line 7, for example, for residential (R-10) service, UNS Gas is currently collecting approximately 33 percent of the revenue from that rate via the fixed customer charge of $7.00 per month. As shown on line 11, Staff's proposed rate design, including the recommended customer charge of $8.50 per month, would result in UNS Gas collecting approximately 36 percent of the revenue via fixed charges. Viewed from a different perspective, as shown on Schedule RD-4, line 13, of the total revenue increase Staff is recommending for residential service (Rate R-10), 60 percent of that would be collected via the increase customer charge revenues.

Similar information for the other rate classes is also shown on Schedule RD-4.

Q. What is shown on Schedule RD-5?

A. Schedule RD-5 shows the derivation of the per-therm distribution rate for each rate class. After accounting for the revenue to be collected via Staff's recommended customer charges for each rate class, the remaining revenue is collected via a per-therm distribution rate. Staff's recommended distribution rates for each rate class are shown on Schedule RD-5, in column G.

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[3] This consists of the $4.721 million base revenue requirement increase plus the $240,000 billing unit adjustment shown on Schedule RD-1.

Q. Please explain the Staff's bill impact comparisons at present and proposed rates.

A. Attachment RCS-S2 shows Staff's bill impact analysis. Each page of Attachment RCS-S2 compares present rates and Staff's recommended rates over a range of usage levels for a particular rate class. The average therms per month are similar to those shown on UNS Gas' Schedule H-4, which presented a typical bill comparison of current and Company-proposed rates. The Staff presentation on Attachment RCS-S2 includes both total bill[4] and base rate only information. Because a significant portion of customers' bills can be for gas cost, especially in the winter months, the percentage increases under the total bill comparison are typically smaller than when comparing the base rate changes only.

To derive the gas costs for the total bill analysis, I added the current base cost of gas of $0.40 per therm to the current February 2007 PGA cost of $0.3844 per therm. As explained in the testimony of Staff witness Robert Gray, both UNS Gas and Staff in the current proceeding are recommending that all gas costs be removed from base rates and addressed in the PGA prospectively.

A review of the information on Attachment RCS-S2 shows that, because of the recommended increases to the customer charge portion of the customer bills, for most usage levels and most rate classes, the recommended rate changes produce a higher percentage increase for lower usage customers within each class and a lower percentage increase for higher usage customers. I discuss bill impacts on individual rate classes in my discussion of Staff's recommended rate design for each rate class, below.

[4] The total bill analysis does not include Staff is recommended DSM adjustor rate of $0.00082 per therm

R-10, Residential Gas Service

Q. Please discuss UNS Gas' proposal to significantly increase the customer charge and first usage block for residential customers.

A. UNS Gas' rate design proposals would increase the residential customer charge from the current $7.00 to $20.00 for summer months and to $11.00 for winter months. UNS Gas' rate design proposals would reduce the per therm margin from $0.3004 to $0.1862. It is understandable that from the Company's financial viewpoint, a heavy frontloading of costs into the customer charge and first usage block is desirable. The testimony of Staff witness Steve Ruback addresses the UNS Gas-proposed frontloading in additional detail. Such a rate design would increase the certainty of the Company's revenue because the customer charge is less impacted by fluctuations in weather and other factors. However, the Company's interest must be balanced by the significant impacts of such a rate design on bills residential customers would face, and other considerations.

Q. Please discuss Staff's general concerns with UNS Gas' proposed front-loading of costs in the residential customer charge.

A. Any time such large changes in rate structure are proposed by a utility, the potential impacts on customers must be carefully considered. Generally speaking, when large shifts such as this are undertaken, some customers bear much more of the brunt of the rate increase than other customers do. The proposed large increases in the customer charge would hit low usage residential customers particularly hard, while high usage customers would see relatively small bill increases. To the extent there is a need or desire to increase the customer charge, a much more gradual movement would be warranted to protect customers from possible rate shock. Staff's recommendations reflect such a gradual approach to increasing the customer charge component of UNS Gas' rates.

Q. What are Staff's recommendations regarding rates for the R-10 tariff?

A. Staff recommends that the basic customer charge be increased from $7.00 to $8.50. Staff further recommends that the distribution margin rate be set at $0.3217 per therm. Staff is not recommending any seasonal rate differential for Rate R-10.

Q. What are the estimated customer bill impacts from Staff's proposed R-10 tariff rates?

A. As shown on Attachment RCS-S2, page 1 of 10, an R-10 customer using 100 therms would see their total bill increase from $115.48 to $119.11, for an increase of $3.63 per month, or 3.14 percent. The corresponding increase in base rates only would be from $37.04 to $40.67, an increase of 9.80 percent per month. Bill impacts for a range of other monthly usage levels for residential customers (Rate R-10) are also presented on Attachment RCS-S2, page 1 of 10. As shown there, total bill increases at Staff's recommended rates range from 2.21 percent (at 500 therms) to 12.96 percent (at 5 therms). Base rate increases (excluding gas costs), range from 7.72 percent (at 500 therms) to 18.94 percent (at 5 therms). At average January usage of 87 therms per month, the proposed increase of $3.36 equates to a 3.31 percent increase in a residential customer's total monthly bill, or a 10.14 percent increase in the non-gas cost portion of the customer's bill.

R-12, Residential Services CARES

Q. Please discuss the development of Staff's proposed rate design for the R-12 tariff for low income customers.

A. Staff witness Julie McNeely-Kirwan addressed the UNS Gas proposals for Residential Service CARES (Rate R-12) in her direct testimony. As she has explained, Staff proposes to retain the existing $7.00 customer charge and the $0.15 per therm winter rate discount (applicable for November through April) up to the first 100 therms. The maximum distribution margin rate discount available for a customer who uses 100 therms in a winter month would thus remain at $15.00. UNS Gas' current tariff, and Staff's recommendation, provides a $0.15 per therm discount on the first 100 therms of usage in winter months, setting an effective cap of $15.00 for a monthly customer discount. For R-12 summer usage and for winter usage in excess of 100 therms per month, Staff recommends the same distribution margin rate as for R-10 of $0.3217 per therm.

Q. What are the customer bill impacts of Staff's recommendations for the R-12 tariff?

A. The estimated impacts over a range of usage are shown on Attachment RCS-S2, page 2 of 10. Depending upon the level of usage, for the summer months of May through October, an R-12 customer would see a total bill increase ranging from $0.11 (at 5 therms) to $10.64 (at 500 therms) per month, which equates to an increase of 0.89 percent to 1.94 percent. Base rate increases (excluding gas costs), range from 6.77 percent (at 500 therms) to 1.29 percent (at 5 therms).

For winter usage, an R-12 customer using less than 100 therms per month would experience increases of no more than $2.13 per month (at usage of 100 therms). As shown on Attachment RCS-S2, page 2 of 10, an R-12 customer using gas in winter months over 100 therms would experience a bill increase of $5.32 per month (at 250 therms), or a 2.02 percent increase. An average R-12 customer, using 64 therms in the winter months, would experience an increase of $1.36 per month, which equates to a total bill increase of 2.04 percent and a base rate (excluding gas cost) increase of approximately 8.18 percent.

C-20, Small Commercial Service

Q. What are Staff's recommendations regarding rates for the C-20 tariff?

A. Staff recommends that the customer charge be increased from $11.00 to $13.50. Staff further recommends that the distribution margin rate be increased from $0.2420 per therm to $0.2651 per therm. As shown on Attachment RCS-S2, page 3 of 10, on a total bill basis, this results in an increase ranging from 2.27 percent (at 10,000 therms) to 5.87 percent (at 50 therms). On a base rate increase basis, this results in an increase ranging from 9.61 percent (at 10,000 therms) to 15.84 percent (at 50 therms).

C-22, Large Commercial Service

Q. What are Staff's recommendations regarding rates for the C22 tariff?

A. Staff recommends that the customer charge be increased from $85.00 to $100. Staff further recommends that the per therm rate be increased from $0.1551 per therm to $0.1731 per therm. As shown on Attachment RCS-S2, page 4 of 10, on a total bill basis, this results in an increase ranging from 1.94 percent (at 75,000 therms) to 2.06 percent (at 10,001 therms). On a base rate increase basis, excluding gas costs, this results in an increase ranging from 11.67 percent (at 75,000 therms) to 11.94 percent (at 10,001 therms).

I-30, Small Volume Industrial Service

Q. What are Staff's recommendations regarding rates for the I-30 tariff?

A. Staff recommends that the customer charge be increased from $11.00 to $13.50. Staff further recommends that the per therm rate be increased from $0.2122 per therm to $0.2369 per therm. As shown on Attachment RCS-S2, page 5 of 10, on a total bill basis, this results in an increase ranging from 2.50 percent (at 10,000 therms) to 6.13 percent (at

50 therms). On a base rate increase basis, excluding gas costs, this results in an increase ranging from 11.69 percent (at 10,000 therms) to 17.26 percent (at 50 therms).

I-32, Large Volume Industrial Service

Q. What are Staff's recommendations regarding rates for the I-32 tariff?

A. Staff recommends that the customer charge be increased from $85.00 to $100. Staff further recommends that the per therm rate be increased from $0.0864 per therm to $0.0965 per therm. As shown on Attachment RCS-S2, page 6 of 10, on a total bill basis, this results in an increase ranging from 1.18 percent (at 150,000 therms) to 1.32 percent (at 10,001 therms). On a base rate increase basis, excluding gas costs, this results in an increase ranging from 11.78 percent (at 150,000 therms) to 12.27 percent (at 10,001 therms).

PA-40, Small Volume Public Authority

Q. What are Staff's recommendations regarding rates for the PA-40 tariff?

A. Staff recommends that the customer charge be increased from $11.00 to $13.50. Staff further recommends that the per therm rate be increased from $0.2354 per therm to $0.2606 per therm. As shown on Attachment RCS-S2, page 7 of 10, on a total bill basis, this results in an increase ranging from 2.49 percent (at 10,000 therms) to 6.07 percent (at 50 therms). On a base rate increase basis, this results in an increase ranging from 10.75 percent (at 10,000 therms) to 16.51 percent (at 50 therms).

PA-42, Large Volume Public Authority

Q. What are Staff's recommendations regarding rates for the PA-42 tariff?

A. Staff recommends that the customer charge be increased from $85.00 to $100. Staff further recommends that the per therm rate be increased from $0.1084 per therm to

$0.1211 per therm. As shown on Attachment RCS-S2, page 8 of 10, on a total bill basis, this results in an increase ranging from 1.43 percent (at 150,000 therms) to 1.58 percent (at 10,001 therms). On a base rate increase basis, excluding gas costs, this results in an increase ranging from 11.75 percent (at 150,000 therms) to 12.15 percent (at 10,001 therms).

PA-44, Special Gas Light Service

Q. What are Staff's recommendations regarding rates for the PA-44 tariff?

A. Staff recommends that the customer charge for Lighting Group A be increased from $13.57 to $15.17, and for Lighting Group B, from $16.28 to $18.20. This is an increase of $1.60 and $1.92 per month or approximately 11.80 percent[5].

IR-60, Irrigation Service

Q. What are Staff's recommendations regarding rates for the IR-60 tariff?

A. Staff recommends that the customer charge be increased from $11.00 to $13.50. Staff further recommends that the per therm rate be increased from $0.2876 per therm to $0.3205 per therm. As shown on Attachment RCS-S2, page 10 of 10, on a total bill basis, this results in an increase ranging from 3.09 percent (at 10,000 therms) to 6.42 percent (at 50 therms). On a base rate increase basis, excluding gas costs, this results in an increase ranging from 11.48 percent (at 10,000 therms) to 16.35 percent (at 50 therms).

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

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[5] As shown on Attachment RCS-S1, Schedules RD-3 and RD-4, Staff targeted an increase of 11.80 percent for this rate class, whose rates consist of the customer charge.

Attachment RCS-S1
To the Supplemental Testimony
Of Staff Witness Ralph C. Smith

Staff Proposed Rate Design Summary
And Proof of Revenue

Attachment RCS-S1

Staff Rate Design Schedules

Accompanying the Direct Testimony of Ralph C. Smith

Schedule	Description	Pages
RD-1	Staff Proof of Revenue at Present and Proposed Rates	2
RD-2	Calculation of CARES (Rate R12) Total Discount for the Winter Months	1
RD-3	Calculation of An Across the Board Increase	1
RD-4	Analysis of Revenues Generated by Fixed Charges	1
RD-5	Calculation of Distribution Rate	1
	Total Pages	6

PROOF OF REVENUE USING THE COMPANY'S BILLING UNITS STATED ON SCHEDULE H-2, PAGE 1 OF 2

Line No.	Class of Service	Adjusted Billed BD (from H-2, page 1) (A)	Existing Rates (B)	Current Revenues (C)	Adjusted Booked Revenue (D)	Difference (E)	Staff Billing Unit Adjustments: Staff Adj. for Customer Annualizaton (F)	Staff Billing Unit Adjustments: Staff Adj. for Weather Normalization (G)	Adjusted Billing units (H)	Current Revenues (I)	Staff Adjusted Average No. of Customers (J)
	Residential Service (R10)										
1	Customer Charge	1,447,632	$ 7.00	$10,133,424			5,883		1,453,515	10,174,605	121,126
2	Distribution Margin Therms	68,951,676	$0.3004	$20,713,083			129,654	4,916	69,086,246	20,753,508	
3	TOTAL R10			$30,846,507	$31,176,937	($330,430)				30,928,113	
	Residential Service Cares (R12)										
4	Customer Charge	67,920	$ 7.00	$475,440			(1,252)		66,668	466,676	5,556
5	Distribution Margin Therms	2,813,844	$0.3004	$845,279			(40,412)	(872)	2,772,560	832,877	
6	TOTAL R12			$1,320,719	$975,486	$345,233				1,299,553	
	Small Volume Commercial Service (C20)										
7	Customer Charge	131,028	$ 11.00	$1,441,308			1,178		132,206	1,454,266	11,017
8	Distribution Margin Therms	29,014,067	$0.2420	$7,021,404			139,670	3,550	29,157,287	7,056,063	
9	TOTAL R20			$8,462,712	$8,531,880	($69,168)				8,510,329	
	Large Volume Commercial Service (C22) and Commercial Transportatjion										
10	Customer Charge	204	$ 85.00	$17,340			4		208	17,680	17
11	Distribution Margin Therms	3,756,735	$0.1551	$582,670			32,215		3,788,950	587,666	
12	TOTAL R22			$600,010	$661,907	($61,897)				605,346	
	Small Volume Industrial Service (I-30)										
13	Customer Charge	156	$ 11.00	$1,716					156	1,716	13
14	Distribution Margin Therms	511,826	$0.2122	$108,609					511,826	108,609	
15	TOTAL I30			$110,325	$109,190	$1,136				110,325	
	Large Volume Industrial Service (I-32)										
16	Customer Charge	228	$ 85.00	$19,380					228	19,380	19
17	Distribution Margin Therms	21,610,146	$0.0864	$1,867,117					21,610,146	1,867,117	
18	TOTAL I32			$1,886,497	$1,971,743	($85,246)				1,886,497	
	Small Volume Public Authority (PA-40)										
19	Customer Charge	12,696	$ 11.00	$139,656			(32)		12,664	139,304	1,055
20	Distribution Margin Therms	5,828,186	$0.2354	$1,371,955			(19,344)	(476)	5,808,366	1,367,289	
21	TOTAL PA40			$1,511,611	$1,527,532	($15,921)				1,506,593	
	Large Volume Public Authority (PA-42)										
22	Customer Charge	108	$ 85.00	$9,180			(4)		104	8,840	9
23	Distribution Margin Therms	5,558,725	$0.1084	$602,566			(33,636)		5,525,089	598,920	
24	TOTAL PA42			$611,746	$637,909	($26,163)				607,760	
	Special Gas Light Service (PA-44)										
25	Customer Charge Lighting Group A	864	$ 13.57	$11,724					864	11,724	
26	Customer Charge Lighting Group B	3,756	$ 16.28	$61,148					3,756	61,148	
27	TOTAL PA44	101,855		$72,872	$73,078	($206)				72,872	
	Irrigation Service (IR-60)										
28	Customer Charge	72	$ 11.00	$792					72	792	6
29	Distribution Margin Therms	86,803	$0.2876	$24,965					86,803	24,965	
30	TOTAL IR60			$25,757	$23,562	$2,194				25,757	
31	**Total Gas Service Revenue at Present Rates**			**$45,448,756**	$45,689,224	($240,468)				**45,553,146**	
32	**Staff Adjusted Revenue at Rresent Rates**			Note A	Note A	Note A				45,793,618	
33	**Difference**								*Difference*	*(240,472)*	
										Note A	
34	Total Bills	1,660,047							1,665,824		
35	Total Monthly Customers	138,340 [B]							138,822 [B]		138,821 [B]
36	Total Distribution Therms	138,233,863							138,347,273		

Notes and Source

Col.A: UNS Gas filing, Schedule H-2, page 1 of 2, adjusted average number of customers (x 12) and adjusted therm sales
UNS Gas filing, Schedule H-2, page 1 of 2, adjusted average number of customers lists 3 customers for PA44; billing units for PA44 on lines 25&26 are from a workpaper
Col.B: UNS Gas filing, Schedule H-3, Present Rates
Col.C: Col.A x Col.B
Col.D: UNS Gas filing, Schedule H-2, page 2 of 2, Adjusted Net Revenues column
Total agrees with UNS Gas filing, Schedule H-1, Adjusted Present Net Revenue subtotal on line 8 of that schedule.
Col.E: Col.C - Col.D
Col.F: Staff workpapers
Col.G: Staff workpapers
Col.H: Col.A + Col.F + Col.G
Col.I: Col.H x Col.B
[A] The billing units from the Company's Schedule H-2, page 1 of 2 produce a net revenue of $45,488,756 which is 240,468 less than what the Company states in Schedule H-2, page 2 of 2.
[B] Includes 3 customers for PA44

UNS Gas Inc. Rate Case; Docket No. G-04204A-06-0463
Staff Proof of Revenue at Present and Proposed Rates

Line	Class of Service	Adjusted Billing Units A	Existing Rates (B)	Current Revenues (C)	Staff Proposed New Rates (D)	Proposed Revenues (E)	Residential Cares (R-12) Winter Discount (F)
	Residential Service (R10)						
1	Customer Charge	1,453,515	7.00	$ 10,174,605	8.50	$ 12,354,878	
2	Distribution Margin Therms	69,086,246	0.3004	$ 20,753,508	0.3217	$ 22,223,452	
3	TOTAL R10			$ 30,928,113		$ 34,578,330	
	Residential Service Cares (R12)						
4	Customer Charge	66,668	7.00	$ 466,676	7.00	$ 466,676	
5	Distribution Margin Therms	2,772,560	0.3004	$ 832,877	0.3217	$ 891,877	$ (320,006)
6	TOTAL R12			$ 1,299,553		$ 1,358,553	
	Small Volume Commercial Service (C20)						
7	Customer Charge	132,206	11.00	$ 1,454,266	13.50	$ 1,784,781	
8	Distribution Margin Therms	29,157,287	0.2420	$ 7,056,063	0.2651	$ 7,729,960	
9	TOTAL C20			$ 8,510,329		$ 9,514,741	
	Large Volume Commercial Service (C22) and Commercial Transportation						
10	Customer Charge	208	85.00	$ 17,680	100.00	$ 20,800	
11	Distribution Margin Therms	3,788,950	0.1551	$ 587,666	0.1731	$ 655,991	
12	TOTAL C22			$ 605,346		$ 676,791	
	Small Volume Industrial Service (I-30)						
13	Customer Charge	156	11.00	$ 1,716	13.50	$ 2,106	
14	Distribution Margin Therms	511,826	0.2122	$ 108,609	0.2369	$ 121,240	
15	TOTAL I30			$ 110,325		$ 123,346	
	Large Volume Industrial Service (I-32) and Industrial Transportation						
16	Customer Charge	228	85.00	$ 19,380	100.00	$ 22,800	
17	Distribution Margin Therms	21,610,146	0.0864	$ 1,867,117	0.0965	$ 2,086,346	
18	TOTAL I32			$ 1,886,497		$ 2,109,146	
	Small Volume Public Authority (PA-40)						
19	Customer Charge	12,664	11.00	$ 139,304	13.50	$ 170,964	
20	Distribution Margin Therms	5,808,366	0.2354	$ 1,367,289	0.2606	$ 1,513,441	
21	TOTAL PA40			$ 1,506,593		$ 1,684,405	
	Large Volume Public Authority (PA-42) and Public Authority Transportation						
22	Customer Charge	104	85.00	$ 8,840	100.00	$ 10,400	
23	Distribution Margin Therms	5,525,089	0.1084	$ 598,920	0.1211	$ 669,089	
24	TOTAL PA42			$ 607,760		$ 679,489	
	Special Gas Light Service (PA-44)						
25	Customer Charge Lighting Group A	864	13.57	$ 11,724	15.17	$ 13,108	
26	Customer Charge Lighting Group B	3,756	16.28	$ 61,148	18.20	$ 68,364	
27	TOTAL PA44			$ 72,872		$ 81,473	
	Irrigation Service (IR-60)						
28	Customer Charge	72	11.00	$ 792	13.50	$ 972	
29	Distribution Margin Therms	86,803	0.2876	$ 24,965	0.3205	$ 27,824	
30	TOTAL IR60			$ 25,757		$ 28,796	
						Increase	
30	**Total Revenue Requirements**			**$ 45,553,146**		$ 4,961,918	**$ 50,515,064**
31	**Staff revenues**			$ 45,793,618		$ 4,721,446	$ 50,515,064
33	*Difference*			*$ (240,472)*		*$ 240,472*	
				Note A			

Notes

[A] The (240,472) billing unit-related difference is incorporated into the development of Staff's Proposed Rates
Staff's proposed rates are designed to recover the adjusted revenue requirement using the adjusted billing determinants in column A.

Attachment RCS-S1
Schedule RD-2

Calculation of CARES (Rate R12) Total Discount for the Winter Months
Discount equals 15 cents off of the per therm rate, up to 100 therms

Provided from STF 15.3

Line	Month	Average monthly therms	Discount	Annualized Customers	R12 Therm-Based Revenue Discount
		(A)	(B)	(C)	(D)
1	Nov	29	0.1500	5,556	$ 24,167
2	Dec	66	0.1500	5,556	$ 55,001
3	Jan	92	0.1500	5,556	$ 76,668
4	Feb	76	0.1500	5,556	$ 63,335
5	March	66	0.1500	5,556	$ 55,001
6	April	55	0.1500	5,556	$ 45,834
7					$ 320,006
8	Average Monthly therms	64			
9	Discount for first 100 therms	0.1500			
10	Average Monthly Savings per customer	9.60			
11	For Six Months	57.60			
12	Annual # of customers	66,668	Schedule RD-1, pages 1 and 2		
13	Monthly customers	5,556	Schedule RD-1, page 2		
14	Total Discount	$ 320,006			

UNS Gas Inc. Rate Case; Docket No. G-04204A-06-0463
Calculation of An Across the Board Increase

Line	Class	Current Net Revenue (A)	Staff Proposed Increase (B)	Difference in Billing units vs Adj. Revenue (C)	Adjusted Proposed Increase (D)	Proposed Net Revenue (E)	Across-The Board Increase (F)
1	Total	45,553,146	4,721,446	240,472	4,961,918	50,515,064	
2	Residential CARES (R12)	1,299,553			59,000		
3	Total without CARES	44,253,593			4,902,918		11.08%
4	Allocation of CARES (R12) Discount				320,006		0.72%
5	**Across the Board %**						**11.80%** (A)
6	Residential (R10)	30,928,113			3,650,217	34,578,330	11.80%
7	Residential Cares (R12)	1,299,553			59,000	1,358,553	4.54% (B)
8	Small Comm Serv (C-20)	8,510,329			1,004,411	9,514,741	11.80%
9	Large Comm Serv (C-22) and Comm Trans	605,346			71,445	676,791	11.80%
10	Sm. Industrial (I-30)	110,325			13,021	123,346	11.80%
11	Large Industrial (I-32) and Industial Trans	1,886,497			222,649	2,109,146	11.80%
12	Sm. Public Authority (PA-40)	1,506,593			177,812	1,684,405	11.80%
13	Lg. Public Authority (PA-42) and PA Trans	607,760			71,729	679,489	11.80%
14	Special Gas Light (PA-44)	72,872			8,601	81,473	11.80%
15	Irrigation (I-60)	25,757			3,040	28,796	11.80%
16	TOTAL	45,553,146			5,281,924	50,835,070	
17	CARES winter therm discount				$ 320,006	$ 320,006	
18	Total Revenue Increase				4,961,918	50,515,064	

Notes and Source

Net Revenue is the adjusted Net Revenue proposed by Staff
(A) Across the board for all classes except Cares class; including discount
(B) To ensure therm rate is same as Residential
See Schedule RD-2 for development of the CARES discount

UNS Gas Inc. Rate Case; Docket No. G-04204A-06-0463
Analysis of Revenues Generated by Fixed Charges

Attachment **RCS-S1**
Schedule RD-4

Line	Description	Totals	Residential R10	Residential Cares R12	Small Comm Serv C20	Large Comm Serv & Comm Trans C22	Sm. Industrial I30	Large Industrial & Industrial Trans I32	Sm. Public Authority PA-40	Lg. Public Authority and Public Authority Trans PA-42	Special Gas Light PA-44 Group A	Special Gas Light PA-44 Group B	Irrigation IR-60
1	**# of Customers**		1,453,515	66,668	132,206	208	156	228	12,664	104	864	3,756	72
	CUSTOMER CHARGE												
	CURRENT												
2	Customer Charge		$ 7.00	$ 7.00	$ 11.00	$ 85.00	$ 11.00	$ 85.00	$ 11.00	$ 85.00	$ 13.57	$ 16.28	$ 11.00
	PROPOSED												
3	Customer Charge		$ 8.50	$ 7.00	$ 13.50	$ 100.00	$ 13.50	$ 100.00	$ 13.50	$ 100.00	$ 15.17	$ 18.20	$ 13.50
	% of Increase												
4	Customer Charge		21.43%	0.00%	22.73%	17.65%	22.73%	17.65%	22.73%	17.65%	11.80%	11.80%	22.73%
	REVENUES GENERATED BY CUSTOMER CHARGE												
5	Current Revenues from Customer Charge	$ 12,356,131	$ 10,174,605	$ 466,676	$ 1,454,266	$ 17,680	$ 1,716	$ 19,380	$ 139,304	$ 8,840	$ 11,724	$ 61,148	$ 792
6	Total Revenues	$ 45,553,146	$ 30,928,113	$ 1,299,553	$ 8,510,329	$ 605,346	$ 110,325	$ 1,886,497	$ 1,506,593	$ 607,760	$ 11,724	$ 61,148	$ 25,757
7	% of fixed charges	27%	33%	36%	17%	3%	2%	1%	9%	1%	100%	100%	3%
	PROPOSED CUSTOMER CHARGE												
8	Proposed Increase	$ 4,961,918	3,650,217	59,000	1,004,411	71,445	13,021	222,649	177,812	71,729	$ 1,384	$ 7,217	3,040
9	**Total Revenues (includes discount)**	$ 50,515,064	34,578,330	1,358,553	9,514,741	676,791	123,346	2,109,146	1,684,405	679,489	13,108	68,364	28,796
10	Proposed Revenues from Customer Charge	$ 14,915,849	$ 12,354,878	$ 466,676	$ 1,784,781	$ 20,800	$ 2,106	$ 22,800	$ 170,964	$ 10,400	$ 13,108	$ 68,364	$ 972
11	% of Fixed Charges	30%	36%	34%	19%	3%	2%	1%	10%	2%	100%	100%	3%
12	Increase in Revenues from Customer Charge	$ 2,559,718	$ 2,180,273	$ -	$ 330,515	$ 3,120	$ 390	$ 3,420	$ 31,660	$ 1,560	$ 1,384	$ 7,217	$ 180
13	Customer Charge Increases as Percent of Total Revenue Increases	52%	60%	0%	33%	4%	3%	2%	18%	2%	100%	100%	6%

Footnotes:
PA-44 Group A and B increase is based on their % of present revenue collected compared to the total

UNS Gas Inc. Rate Case; Docket No. G-04204A-06-0463
Calculation of Distribution Rate

Line	Class	Revenue Increase (A)	Current Revenues (B)	Proposed Revenues (C)	Proposed Cust. Charge Rev. (D)	Difference (E)	Distribution Therms (F)	Distribution Rate (G)
1	Total	$ 4,961,918	$ 45,553,146	$ 50,515,064			138,347,273	
2	Residential (R-10)	3,650,217	$ 30,928,113	$ 34,578,330	$ 12,354,878	$ 22,223,452	69,086,246	$ 0.3217
3	Residential Cares (R-12) (Note A)	59,000	$ 1,299,553	$ 1,358,553	$ 466,676	$ 891,877	2,772,560	$ 0.3217
4	Small Comm Serv (C-20)	1,004,411	$ 8,510,329	$ 9,514,741	$ 1,784,781	$ 7,729,960	29,157,287	$ 0.2651
5	Large Comm Serv (C-22) and Comm Trans	71,445	$ 605,346	$ 676,791	$ 20,800	$ 655,991	3,788,950	$ 0.1731
6	Sm. Industrial (I-30)	13,021	$ 110,325	$ 123,346	$ 2,106	$ 121,240	511,826	$ 0.2369
7	Large Industrial (I-32) and Trans	222,649	$ 1,886,497	$ 2,109,146	$ 22,800	$ 2,086,346	21,610,146	$ 0.0965
8	Sm. Public Authority (PA-40)	177,812	$ 1,506,593	$ 1,684,405	$ 170,964	$ 1,513,441	5,808,366	$ 0.2606
9	Lg. Public Authority (PA-42) and Trans	71,729	$ 607,760	$ 679,489	$ 10,400	$ 669,089	5,525,089	$ 0.1211
10	Special Gas Light (PA-44) (Note B)	8,601	$ 72,872	$ 81,473	$ 81,473			
11	Irrigation (I-60)	3,040	$ 25,757	$ 28,796	$ 972	$ 27,824	86,803	$ 0.3205
12	TOTALS	$ 5,281,924	$ 45,553,146	$ 50,835,070	$ 14,915,849	$ 35,919,221	138,347,273	
13	CARES winter discount	$ (320,006)		$ (320,006)				
14	TOTALS after reflecting CARES discount	$ 4,961,918	$ 45,553,146	$ 50,515,064				

Notes

Line	Note A: Calculation of Discount for Residential Cares (R12)	
		$ 57.60
15	Total Annual Customers	66,668
16	Total Monthly Customers	5,556
17	Total Discount for Six months	$ 320,006

Note B: Rate PA-44 has Customer Charges Only

Col.D, Customer Charge Revenue amounts are from Schedule RD-1, page 2, Col.E; amounts on Schedule RD-4, line 10, may differ slightly for some rate classes due to rounding.

Attachment RCS-S2
To the Supplemental Testimony
Of Staff Witness Ralph C. Smith

Bill Impact Analysis
Of Staff Proposed Rate Design

Note: When discussing rate design and representing impacts of various rate design characteristics, for the total bill impact comparisons, I have included the current base cost of gas and the current (February 2007) PGA rate. Both UNS Gas and Staff in the current proceeding are recommending that all gas costs be removed from base rates and addressed in the PGA prospectively. The total bill impact comparisons presented here are exclusive of the Staff's recommended DSM rate of $0.00082 per therm.

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Residential Service (R10)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge (Sum: Apr-Nov)	$7.00	$8.50	A & C
2	Distribution Margin Therms	$ 0.3004	$ 0.3217	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

	Average Therms Per Month	Present Rates: Customer Charge	Present Rates: Distribution Margin	Present Rates: Base Rates	Present Rates: Gas Cost	Present Rates: Total Bill	Proposed Rates: Customer Charge	Proposed Rates: Distribution Margin	Proposed Rates: Base Rates	Proposed Rates: Gas Cost	Proposed Rates: Total Bill	Total Bill: Proposed Increase $	Total Bill: Proposed Increase %	Base Rates Only: Proposed Increase $	Base Rates Only: Proposed Increase %
6	5	$7.00	$ 1.50	$8.50	$ 3.92	$12.42	$8.50	$ 1.61	$10.11	$ 3.92	$14.03	$1.61	12.96%	$1.61	18.94%
7	10	$7.00	$ 3.00	$10.00	$ 7.84	$17.84	$8.50	$ 3.22	$11.72	$ 7.84	$19.56	$1.72	9.64%	$1.72	17.20%
8	20	$7.00	$ 6.01	$13.01	$ 15.69	$28.70	$8.50	$ 6.43	$14.93	$ 15.69	$30.62	$1.92	6.69%	$1.92	14.76%
9	35	$7.00	$ 10.51	$17.51	$ 27.45	$44.96	$8.50	$ 11.26	$19.76	$ 27.45	$47.21	$2.25	5.00%	$2.25	12.85%
10	50	$7.00	$ 15.02	$22.02	$ 39.22	$61.24	$8.50	$ 16.08	$24.58	$ 39.22	$63.80	$2.56	4.18%	$2.56	11.63%
11	75	$7.00	$ 22.53	$29.53	$ 58.83	$88.36	$8.50	$ 24.13	$32.63	$ 58.83	$91.46	$3.10	3.51%	$3.10	10.50%
12	100	$7.00	$ 30.04	$37.04	$ 78.44	$115.48	$8.50	$ 32.17	$40.67	$ 78.44	$119.11	$3.63	3.14%	$3.63	9.80%
13	250	$7.00	$ 75.10	$82.10	$ 196.10	$278.20	$8.50	$ 80.42	$88.92	$ 196.10	$285.02	$6.82	2.45%	$6.82	8.31%
14	500	$7.00	$ 150.20	$157.20	$ 392.20	$549.40	$8.50	$ 160.84	$169.34	$ 392.20	$561.54	$12.14	2.21%	$12.14	7.72%

	Rate Component	Present Rates	Staff Proposed	Notes
15	Customer Charge (Winter: Dec-Mar)	$7.00	$8.50	A & C
16	Distribution Margin Therms	$ 0.3004	$ 0.3217	A
17	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
18	Base gas cost	$ 0.4000	$ 0.4000	B
19	Gas Cost Subtotal	$ 0.7844	$ 0.7844	

	Average Therms Per Month	Present Rates: Customer Charge	Present Rates: Distribution Margin	Present Rates: Base Rates	Present Rates: Gas Cost	Present Rates: Total Bill	Proposed Rates: Customer Charge	Proposed Rates: Distribution Margin	Proposed Rates: Base Rates	Proposed Rates: Gas Cost	Proposed Rates: Total Bill	Total Bill: Proposed Increase $	Total Bill: Proposed Increase %	Base Rates Only: Proposed Increase $	Base Rates Only: Proposed Increase %
20	5	$7.00	$ 1.50	$8.50	$ 3.92	$12.42	$8.50	$ 1.61	$10.11	$ 3.92	$14.03	$1.61	12.96%	$1.61	18.94%
21	10	$7.00	$ 3.00	$10.00	$ 7.84	$17.84	$8.50	$ 3.22	$11.72	$ 7.84	$19.56	$1.72	9.64%	$1.72	17.20%
22	20	$7.00	$ 6.01	$13.01	$ 15.69	$28.70	$8.50	$ 6.43	$14.93	$ 15.69	$30.62	$1.92	6.69%	$1.92	14.76%
23	35	$7.00	$ 10.51	$17.51	$ 27.45	$44.96	$8.50	$ 11.26	$19.76	$ 27.45	$47.21	$2.25	5.00%	$2.25	12.85%
24	50	$7.00	$ 15.02	$22.02	$ 39.22	$61.24	$8.50	$ 16.08	$24.58	$ 39.22	$63.80	$2.56	4.18%	$2.56	11.63%
25	75	$7.00	$ 22.53	$29.53	$ 58.83	$88.36	$8.50	$ 24.13	$32.63	$ 58.83	$91.46	$3.10	3.51%	$3.10	10.50%
26	100	$7.00	$ 30.04	$37.04	$ 78.44	$115.48	$8.50	$ 32.17	$40.67	$ 78.44	$119.11	$3.63	3.14%	$3.63	9.80%
27	250	$7.00	$ 75.10	$82.10	$ 196.10	$278.20	$8.50	$ 80.42	$88.92	$ 196.10	$285.02	$6.82	2.45%	$6.82	8.31%
28	500	$7.00	$ 150.20	$157.20	$ 392.20	$549.40	$8.50	$ 160.84	$169.34	$ 392.20	$561.54	$12.14	2.21%	$12.14	7.72%
	Typical Jan Usage														
29	87	$7.00	$ 26.13	$33.13	$ 68.24	$101.37	$8.50	$ 27.99	$36.49	$ 68.24	$104.73	$3.36	3.31%	$3.36	10.14%

Notes
- A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
- B Cost of Gas Inputs workpaper
- C UNS Gas is proposing a different customer charge rate of $20 and $11 per month for summer and winter, respectively. Staff recommends the same customer charge rate for all months.

R10

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Residential Service CARES (R12)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge (Sum: May-Oct)	$7.00	$7.00	A
2	Distribution Margin Therms	$ 0.3004	$ 0.3217	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

Line	Average Therms Per Month	Present Rates Customer Charge	Present Rates Distribution Margin	Present Rates Base Rates	Present Rates Gas Cost	Present Rates Total Bill	Proposed Rates Customer Charge	Proposed Rates Distribution Margin	Proposed Rates Base Rates	Proposed Rates Gas Cost	Proposed Rates Total Bill	Total Bill Proposed Increase $	Total Bill Proposed Increase %	Base Rates Only Proposed Increase $	Base Rates Only Proposed Increase %
6	5	$7.00	$ 1.50	$8.50	$ 3.92	$12.42	$7.00	$ 1.61	$8.61	$ 3.92	$12.53	$0.11	0.89%	$0.11	1.29%
7	10	$7.00	$ 3.00	$10.00	$ 7.84	$17.84	$7.00	$ 3.22	$10.22	$ 7.84	$18.06	$0.22	1.23%	$0.22	2.20%
8	20	$7.00	$ 6.01	$13.01	$ 15.69	$28.70	$7.00	$ 6.43	$13.43	$ 15.69	$29.12	$0.42	1.46%	$0.42	3.23%
9	35	$7.00	$ 10.51	$17.51	$ 27.45	$44.96	$7.00	$ 11.26	$18.26	$ 27.45	$45.71	$0.75	1.67%	$0.75	4.28%
10	50	$7.00	$ 15.02	$22.02	$ 39.22	$61.24	$7.00	$ 16.08	$23.08	$ 39.22	$62.30	$1.06	1.73%	$1.06	4.81%
11	75	$7.00	$ 22.53	$29.53	$ 58.83	$88.36	$7.00	$ 24.13	$31.13	$ 58.83	$89.96	$1.60	1.81%	$1.60	5.42%
12	100	$7.00	$ 30.04	$37.04	$ 78.44	$115.48	$7.00	$ 32.17	$39.17	$ 78.44	$117.61	$2.13	1.84%	$2.13	5.75%
13	250	$7.00	$ 75.10	$82.10	$ 196.10	$278.20	$7.00	$ 80.42	$87.42	$ 196.10	$283.52	$5.32	1.91%	$5.32	6.48%
14	500	$7.00	$ 150.20	$157.20	$ 392.20	$549.40	$7.00	$ 160.84	$167.84	$ 392.20	$560.04	$10.64	1.94%	$10.64	6.77%

Line	Rate Component	Present Rates	Staff Proposed	Notes
15	Customer Charge (Winter)	$7.00	$7.00	A & C
16	Distribution Margin Therms	$ 0.3004	$ 0.3217	A
16a	Margin Rate Discount (Nov-Apr <100 therms)	$ 0.1500	$ 0.1500	C
17	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
18	Base gas cost	$ 0.4000	$ 0.4000	B
19	Gas Cost Subtotal	$ 0.7844	$ 0.7844	

Line	Average Therms Per Month	Present Rates Customer Charge	Present Rates Distribution Margin	Present Rates Base Rates	Present Rates Gas Cost	Present Rates Total Bill	Proposed Rates Customer Charge	Proposed Rates Distribution Margin	Proposed Rates Base Rates	Proposed Rates Gas Cost	Proposed Rates Total Bill	Total Bill Proposed Increase $	Total Bill Proposed Increase %	Base Rates Only Proposed Increase $	Base Rates Only Proposed Increase %
20	5	$7.00	$ 0.75	$7.75	$ 3.92	$11.67	$7.00	$ 0.86	$7.86	$ 3.92	$11.78	$0.11	0.94%	$0.11	1.42%
21	10	$7.00	$ 1.50	$8.50	$ 7.84	$16.34	$7.00	$ 1.72	$8.72	$ 7.84	$16.56	$0.22	1.35%	$0.22	2.59%
22	20	$7.00	$ 3.01	$10.01	$ 15.69	$25.70	$7.00	$ 3.43	$10.43	$ 15.69	$26.12	$0.42	1.63%	$0.42	4.20%
23	35	$7.00	$ 5.26	$12.26	$ 27.45	$39.71	$7.00	$ 6.01	$13.01	$ 27.45	$40.46	$0.75	1.89%	$0.75	6.12%
24	50	$7.00	$ 7.52	$14.52	$ 39.22	$53.74	$7.00	$ 8.58	$15.58	$ 39.22	$54.80	$1.06	1.97%	$1.06	7.30%
25	75	$7.00	$ 11.28	$18.28	$ 58.83	$77.11	$7.00	$ 12.88	$19.88	$ 58.83	$78.71	$1.60	2.07%	$1.60	8.75%
26	100	$7.00	$ 15.04	$22.04	$ 78.44	$100.48	$7.00	$ 17.17	$24.17	$ 78.44	$102.61	$2.13	2.12%	$2.13	9.66%
27	250	$7.00	$ 60.10	$67.10	$ 196.10	$263.20	$7.00	$ 65.42	$72.42	$ 196.10	$268.52	$5.32	2.02%	$5.32	7.93%
28	500	$7.00	$ 135.20	$142.20	$ 392.20	$534.40	$7.00	$ 145.84	$152.84	$ 392.20	$545.04	$10.64	1.99%	$10.64	7.48%

Line	Average	Present Rates Customer Charge	Present Rates Distribution Margin	Present Rates Base Rates	Present Rates Gas Cost	Present Rates Total Bill	Proposed Rates Customer Charge	Proposed Rates Distribution Margin	Proposed Rates Base Rates	Proposed Rates Gas Cost	Proposed Rates Total Bill	Total Bill Proposed Increase $	Total Bill Proposed Increase %	Base Rates Only Proposed Increase $	Base Rates Only Proposed Increase %
29	64	$7.00	$ 9.63	$16.63	$ 50.20	$66.83	$7.00	$ 10.99	$17.99	$ 50.20	$68.19	$1.36	2.04%	$1.36	8.18%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper
C Direct testimony of Staff witness Julie McNeely-Kirwan

Line 27, Distribution Margin

Therms	Present Rate	Present Amount	Proposed Rate	Proposed Amount
100	$ 0.1504	$ 15.04	$ 0.1717	$ 17.17
150	$ 0.3004	$ 45.06	$ 0.3217	$ 48.25
		$ 60.10		$ 65.42

Line 28, Distribution Margin

Therms	Present Rate	Present Amount	Proposed Rate	Proposed Amount
100	$ 0.1504	$ 15.04	$ 0.1717	$ 17.17
400	$ 0.3004	$ 120.16	$ 0.3217	$ 128.67
		$ 135.20		$ 145.84

R12

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Small Commercial Service (C20)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2420	$ 0.2651	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 12.10	$23.10	$ 39.22	$62.32	$13.50	$ 13.26	$26.76	$ 39.22	$65.98	$3.66	5.87%	$3.66	15.84%
7	100	$11.00	$ 24.20	$35.20	$ 78.44	$113.64	$13.50	$ 26.51	$40.01	$ 78.44	$118.45	$4.81	4.23%	$4.81	13.66%
8	500	$11.00	$ 121.00	$132.00	$ 392.20	$524.20	$13.50	$ 132.56	$146.06	$ 392.20	$538.26	$14.06	2.68%	$14.06	10.65%
9	1,000	$11.00	$ 242.00	$253.00	$ 784.40	$1,037.40	$13.50	$ 265.11	$278.61	$ 784.40	$1,063.01	$25.61	2.47%	$25.61	10.12%
10	1,500	$11.00	$ 363.00	$374.00	$ 1,176.60	$1,550.60	$13.50	$ 397.67	$411.17	$ 1,176.60	$1,587.77	$37.17	2.40%	$37.17	9.94%
11	2,500	$11.00	$ 605.00	$616.00	$ 1,961.00	$2,577.00	$13.50	$ 662.78	$676.28	$ 1,961.00	$2,637.28	$60.28	2.34%	$60.28	9.79%
12	5,000	$11.00	$1,210.00	$1,221.00	$ 3,922.00	$5,143.00	$13.50	$ 1,325.56	$1,339.06	$ 3,922.00	$5,261.06	$118.06	2.30%	$118.06	9.67%
13	7,500	$11.00	$1,815.00	$1,826.00	$ 5,883.00	$7,709.00	$13.50	$ 1,988.34	$2,001.84	$ 5,883.00	$7,884.84	$175.84	2.28%	$175.84	9.63%
14	10,000	$11.00	$2,420.00	$2,431.00	$ 7,844.00	$10,275.00	$13.50	$ 2,651.12	$2,664.62	$ 7,844.00	$10,508.62	$233.62	2.27%	$233.62	9.61%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Large Commercial Service (C22)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$85.00	$100.00	A
2	Distribution Margin Therms	$ 0.1551	$ 0.1731	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	*Distribution* Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total *Bill*	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	10,001	$85.00	$ 1,551.16	$1,636.16	$ 7,844.78	$9,480.94	$100.00	$ 1,731.50	$1,831.50	$ 7,844.78	$9,676.28	$195.34	2.06%	$195.34	11.94%
7	12,500	$85.00	$ 1,938.75	$2,023.75	$ 9,805.00	$11,828.75	$100.00	$ 2,164.16	$2,264.16	$ 9,805.00	$12,069.16	$240.41	2.03%	$240.41	11.88%
8	15,000	$85.00	$ 2,326.50	$2,411.50	$ 11,766.00	$14,177.50	$100.00	$ 2,596.99	$2,696.99	$ 11,766.00	$14,462.99	$285.49	2.01%	$285.49	11.84%
9	17,500	$85.00	$ 2,714.25	$2,799.25	$ 13,727.00	$16,526.25	$100.00	$ 3,029.82	$3,129.82	$ 13,727.00	$16,856.82	$330.57	2.00%	$330.57	11.81%
10	20,000	$85.00	$ 3,102.00	$3,187.00	$ 15,688.00	$18,875.00	$100.00	$ 3,462.65	$3,562.65	$ 15,688.00	$19,250.65	$375.65	1.99%	$375.65	11.79%
11	25,000	$85.00	$ 3,877.50	$3,962.50	$ 19,610.00	$23,572.50	$100.00	$ 4,328.31	$4,428.31	$ 19,610.00	$24,038.31	$465.81	1.98%	$465.81	11.76%
12	30,000	$85.00	$ 4,653.00	$4,738.00	$ 23,532.00	$28,270.00	$100.00	$ 5,193.98	$5,293.98	$ 23,532.00	$28,825.98	$555.98	1.97%	$555.98	11.73%
13	45,000	$85.00	$ 6,979.50	$7,064.50	$ 35,298.00	$42,362.50	$100.00	$ 7,790.97	$7,890.97	$ 35,298.00	$43,188.97	$826.47	1.95%	$826.47	11.70%
14	75,000	$85.00	$ 11,632.50	$11,717.50	$ 58,830.00	$70,547.50	$100.00	$ 12,984.94	$13,084.94	$ 58,830.00	$71,914.94	$1,367.44	1.94%	$1,367.44	11.67%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Small Volume Industrial Service (I-30)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2122	$ 0.2369	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
Line	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 10.61	$21.61	$ 39.22	$60.83	$13.50	$ 11.84	$25.34	$ 39.22	$64.56	$3.73	6.13%	$3.73	17.26%
7	100	$11.00	$ 21.22	$32.22	$ 78.44	$110.66	$13.50	$ 23.69	$37.19	$ 78.44	$115.63	$4.97	4.49%	$4.97	15.43%
8	500	$11.00	$ 106.10	$117.10	$ 392.20	$509.30	$13.50	$ 118.44	$131.94	$ 392.20	$524.14	$14.84	2.91%	$14.84	12.67%
9	1,000	$11.00	$ 212.20	$223.20	$ 784.40	$1,007.60	$13.50	$ 236.88	$250.38	$ 784.40	$1,034.78	$27.18	2.70%	$27.18	12.18%
10	1,500	$11.00	$ 318.30	$329.30	$ 1,176.60	$1,505.90	$13.50	$ 355.32	$368.82	$ 1,176.60	$1,545.42	$39.52	2.62%	$39.52	12.00%
11	2,500	$11.00	$ 530.50	$541.50	$ 1,961.00	$2,502.50	$13.50	$ 592.20	$605.70	$ 1,961.00	$2,566.70	$64.20	2.57%	$64.20	11.86%
12	5,000	$11.00	$1,061.00	$1,072.00	$ 3,922.00	$4,994.00	$13.50	$ 1,184.39	$1,197.89	$ 3,922.00	$5,119.89	$125.89	2.52%	$125.89	11.74%
13	7,500	$11.00	$1,591.50	$1,602.50	$ 5,883.00	$7,485.50	$13.50	$ 1,776.59	$1,790.09	$ 5,883.00	$7,673.09	$187.59	2.51%	$187.59	11.71%
14	10,000	$11.00	$2,122.00	$2,133.00	$ 7,844.00	$9,977.00	$13.50	$ 2,368.78	$2,382.28	$ 7,844.00	$10,226.28	$249.28	2.50%	$249.28	11.69%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Larve Volume Industrial Service (I-32)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$85.00	$100.00	A
2	Distribution Margin Therms	$ 0.0864	$ 0.0965	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	10,001	$85.00	$ 864.09	$949.09	$ 7,844.78	$8,793.87	$100.00	$ 965.54	$1,065.54	$ 7,844.78	$8,910.32	$116.45	1.32%	$116.45	12.27%
7	15,000	$85.00	$ 1,296.00	$1,381.00	$ 11,766.00	$13,147.00	$100.00	$ 1,448.17	$1,548.17	$ 11,766.00	$13,314.17	$167.17	1.27%	$167.17	12.10%
8	20,000	$85.00	$ 1,728.00	$1,813.00	$ 15,688.00	$17,501.00	$100.00	$ 1,930.89	$2,030.89	$ 15,688.00	$17,718.89	$217.89	1.25%	$217.89	12.02%
9	30,000	$85.00	$ 2,592.00	$2,677.00	$ 23,532.00	$26,209.00	$100.00	$ 2,896.34	$2,996.34	$ 23,532.00	$26,528.34	$319.34	1.22%	$319.34	11.93%
10	50,000	$85.00	$ 4,320.00	$4,405.00	$ 39,220.00	$43,625.00	$100.00	$ 4,827.24	$4,927.24	$ 39,220.00	$44,147.24	$522.24	1.20%	$522.24	11.86%
11	75,000	$85.00	$ 6,480.00	$6,565.00	$ 58,830.00	$65,395.00	$100.00	$ 7,240.86	$7,340.86	$ 58,830.00	$66,170.86	$775.86	1.19%	$775.86	11.82%
12	100,000	$85.00	$ 8,640.00	$8,725.00	$ 78,440.00	$87,165.00	$100.00	$ 9,654.47	$9,754.47	$ 78,440.00	$88,194.47	$1,029.47	1.18%	$1,029.47	11.80%
13	125,000	$85.00	$ 10,800.00	$10,885.00	$ 98,050.00	$108,935.00	$100.00	$ 12,068.09	$12,168.09	$ 98,050.00	$110,218.09	$1,283.09	1.18%	$1,283.09	11.79%
14	150,000	$85.00	$ 12,960.00	$13,045.00	$ 117,660.00	$130,705.00	$100.00	$ 14,481.71	$14,581.71	$ 117,660.00	$132,241.71	$1,536.71	1.18%	$1,536.71	11.78%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Small Volume Public Authority (PA-40)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2354	$ 0.2606	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 11.77	$22.77	$ 39.22	$61.99	$13.50	$ 13.03	$26.53	$ 39.22	$65.75	$3.76	6.07%	$3.76	16.51%
7	100	$11.00	$ 23.54	$34.54	$ 78.44	$112.98	$13.50	$ 26.06	$39.56	$ 78.44	$118.00	$5.02	4.44%	$5.02	14.53%
8	500	$11.00	$ 117.70	$128.70	$ 392.20	$520.90	$13.50	$ 130.28	$143.78	$ 392.20	$535.98	$15.08	2.89%	$15.08	11.72%
9	1,000	$11.00	$ 235.40	$246.40	$ 784.40	$1,030.80	$13.50	$ 260.56	$274.06	$ 784.40	$1,058.46	$27.66	2.68%	$27.66	11.23%
10	1,500	$11.00	$ 353.10	$364.10	$ 1,176.60	$1,540.70	$13.50	$ 390.84	$404.34	$ 1,176.60	$1,580.94	$40.24	2.61%	$40.24	11.05%
11	2,500	$11.00	$ 588.50	$599.50	$ 1,961.00	$2,560.50	$13.50	$ 651.41	$664.91	$ 1,961.00	$2,625.91	$65.41	2.55%	$65.41	10.91%
12	5,000	$11.00	$1,177.00	$1,188.00	$ 3,922.00	$5,110.00	$13.50	$ 1,302.81	$1,316.31	$ 3,922.00	$5,238.31	$128.31	2.51%	$128.31	10.80%
13	7,500	$11.00	$1,765.50	$1,776.50	$ 5,883.00	$7,659.50	$13.50	$ 1,954.22	$1,967.72	$ 5,883.00	$7,850.72	$191.22	2.50%	$191.22	10.76%
14	10,000	$11.00	$2,354.00	$2,365.00	$ 7,844.00	$10,209.00	$13.50	$ 2,605.62	$2,619.12	$ 7,844.00	$10,463.12	$254.12	2.49%	$254.12	10.75%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Large Volume Public Authority (PA-42)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$85.00	$100.00	A
2	Distribution Margin Therms	$ 0.1084	$ 0.1211	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	10,001	$85.00	$ 1,084.11	$1,169.11	$ 7,844.78	$9,013.89	$100.00	$ 1,211.12	$1,311.12	$ 7,844.78	$9,155.90	$142.01	1.58%	$142.01	12.15%
7	15,000	$85.00	$ 1,626.00	$1,711.00	$ 11,766.00	$13,477.00	$100.00	$ 1,816.50	$1,916.50	$ 11,766.00	$13,682.50	$205.50	1.52%	$205.50	12.01%
8	20,000	$85.00	$ 2,168.00	$2,253.00	$ 15,688.00	$17,941.00	$100.00	$ 2,422.00	$2,522.00	$ 15,688.00	$18,210.00	$269.00	1.50%	$269.00	11.94%
9	30,000	$85.00	$ 3,252.00	$3,337.00	$ 23,532.00	$26,869.00	$100.00	$ 3,633.00	$3,733.00	$ 23,532.00	$27,265.00	$396.00	1.47%	$396.00	11.87%
10	50,000	$85.00	$ 5,420.00	$5,505.00	$ 39,220.00	$44,725.00	$100.00	$ 6,055.01	$6,155.01	$ 39,220.00	$45,375.01	$650.01	1.45%	$650.01	11.81%
11	75,000	$85.00	$ 8,130.00	$8,215.00	$ 58,830.00	$67,045.00	$100.00	$ 9,082.51	$9,182.51	$ 58,830.00	$68,012.51	$967.51	1.44%	$967.51	11.78%
12	100,000	$85.00	$ 10,840.00	$10,925.00	$ 78,440.00	$89,365.00	$100.00	$ 12,110.01	$12,210.01	$ 78,440.00	$90,650.01	$1,285.01	1.44%	$1,285.01	11.76%
13	125,000	$85.00	$ 13,550.00	$13,635.00	$ 98,050.00	$111,685.00	$100.00	$ 15,137.52	$15,237.52	$ 98,050.00	$113,287.52	$1,602.52	1.43%	$1,602.52	11.75%
14	150,000	$85.00	$ 16,260.00	$16,345.00	$ 117,660.00	$134,005.00	$100.00	$ 18,165.02	$18,265.02	$ 117,660.00	$135,925.02	$1,920.02	1.43%	$1,920.02	11.75%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Special Gas Light Service (PA-44)

Line	**Rate Component**	Present Rates	Staff Proposed	Increase $	Note
1	Customer Charge Lighting Group A	$13.57	**$15.17**	$1.60	A
2	Customer Charge Lighting Group B	$16.28	**$18.20**	$1.92	A

	Annual Bill Impact	Present	Proposed	Increase $	Increase %
3	*Customer Charge Lighting Group A*	$162.84	$182.06	$19.22	11.80%
4	Customer Charge Lighting Group B	$195.36	$218.42	$23.06	11.80%

Notes

A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Irrigation Service (IR-60)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge (Sum: Apr-Nov)	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2876	$0.3205	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

Line	Average Therms Per Month	Present Rates Customer Charge	Present Rates Distribution Margin	Present Rates Base Rates	Present Rates Gas Cost	Present Rates Total Bill	Proposed Rates Customer Charge	Proposed Rates Distribution Margin	Proposed Rates Base Rates	Proposed Rates Gas Cost	Proposed Rates Total Bill	Total Bill Proposed Increase $	Total Bill Proposed Increase %	Base Rates Only Proposed Increase $	Base Rates Only Proposed Increase %
6	50	$11.00	$ 14.38	$25.38	$ 39.22	$64.60	$13.50	$ 16.03	$29.53	$ 39.22	$68.75	$4.15	6.42%	$4.15	16.35%
7	100	$11.00	$ 28.76	$39.76	$ 78.44	$118.20	$13.50	$ 32.05	$45.55	$ 78.44	$123.99	$5.79	4.90%	$5.79	14.56%
8	500	$11.00	$ 143.80	$154.80	$ 392.20	$547.00	$13.50	$ 160.25	$173.75	$ 392.20	$565.95	$18.95	3.46%	$18.95	12.24%
9	1,000	$11.00	$ 287.60	$298.60	$ 784.40	$1,083.00	$13.50	$ 320.50	$334.00	$ 784.40	$1,118.40	$35.40	3.27%	$35.40	11.86%
10	1,500	$11.00	$ 431.40	$442.40	$ 1,176.60	$1,619.00	$13.50	$ 480.75	$494.25	$ 1,176.60	$1,670.85	$51.85	3.20%	$51.85	11.72%
11	2,500	$11.00	$ 719.00	$730.00	$ 1,961.00	$2,691.00	$13.50	$ 801.25	$814.75	$ 1,961.00	$2,775.75	$84.75	3.15%	$84.75	11.61%
12	5,000	$11.00	$1,438.00	$1,449.00	$ 3,922.00	$5,371.00	$13.50	$ 1,602.50	$1,616.00	$ 3,922.00	$5,538.00	$167.00	3.11%	$167.00	11.53%
13	7,500	$11.00	$2,157.00	$2,168.00	$ 5,883.00	$8,051.00	$13.50	$ 2,403.75	$2,417.25	$ 5,883.00	$8,300.25	$249.25	3.10%	$249.25	11.50%
14	10,000	$11.00	$2,876.00	$2,887.00	$ 7,844.00	$10,731.00	$13.50	$ 3,205.00	$3,218.50	$ 7,844.00	$11,062.50	$331.50	3.09%	$331.50	11.48%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

SURREBUTTAL

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

APRIL 4, 2007

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013
AND G-04204A-05-0831

My surrebuttal testimony addresses the following issues:

- The Company's proposed revenue requirement
- Adjustments to test year data
- Rate base, including construction work in progress
- Test year revenues (including number of customers and usage) and expenses
- Staff's updated proposed rate design, based on changes to the base rate revenue requirement reflected in my surrebuttal testimony

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement on a base rate increase of $9.647 million is overstated. As described in my surrebuttal testimony, based on the information received and reviewed to date, I recommend that UNS Gas be authorized a base rate increase of $4.312 million. This represents a net decrease of $409 thousand from the $4.721 million base rate increase described in my direct testimony. Staff's surrebuttal recommendation for the amount of base rate revenue increase is based upon applying an appropriately adjusted weighted cost of capital to Staff's adjusted Fair Value Rate Base. The comparable base rate increase, applying Staff's recommended weighted cost of capital to adjusted Original Cost Rate Base, is $4.336 million.

- The following table shows Staff's recommended adjustments to UNS Gas' proposed original cost and fair value rate base that should be made, and identifies the changes from Staff's direct to Staff's surrebuttal position:

Summary of Staff Adjustments to Rate Base		**Staff Rebuttal**	**Staff Direct**		
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)	Difference	Revised
B-1	Remove Construction Work in Progress	$ (7,189,231)	$ (7,189,231)	$ -	
B-2	Remove GIS Deferral	$ (897,068)	$ (897,068)	$ -	
B-3	Cash Working Capital - Lead/Lag Study	$ 776,874	$ 770,960	$ 5,914	Yes
B-4	Accumulated Deferred Income Taxes	$ 195,336	$ 195,336	$ -	
	Total of Staff Adjustments	$ (7,114,089)	$ (7,120,003)	$ 5,914	Yes
	UNS Proposed Rate Base (Original Cost)	$ 161,661,361	$ 161,661,361	$ -	
	Staff Proposed Rate Base (Original Cost)	$ 154,547,272	$ 154,541,358	$ 5,914	**Yes**

- The following table shows Staff's recommended adjustments to UNS Gas' proposed revenues, expenses and net operating income that should be made, and identifies the changes from Staff's direct to Staff's surrebuttal position:

Summary of Staff Adjustments to Net Operating Income

Adj. No.	Description	Staff Rebuttal Increase (Decrease)	Staff Direct Increase (Decrease)	Difference	Revised
C-1	Revenue Annualization	$ 62,896	$ 62,896	$ -	
C-2	Weather Normalization	$ 1,205	$ 1,205	$ -	
C-3	Adjustment to Bad Debt Expense	$ (776)	$ (776)	$ -	
C-4	Remove Depreciation & Property Taxes for CWIP	$ 222,981	$ 222,981	$ -	
C-5	Remove Amortization of Deferred GIS Cost	$ 183,606	$ 183,606	$ -	
C-6	Incentive Compensation and SERP	$ 164,204	$ 164,204	$ -	
C-7	Emergency Bill Assistance Expense	$ (13,263)	$ (13,263)	$ -	
C-8	Nonrecurring Severance Payment Expense	$ -	$ 32,167	$ (32,167)	Yes
C-9	Overtime Payroll Expense	$ 75,531	$ 75,531	$ -	
C-10	Payroll Tax Expense	$ 5,740	$ 8,201	$ (2,461)	Yes
C-11	Nonrecurring FERC Rate Case Legal Expense	$ 190,992	$ 190,992	$ -	
C-12	Property Tax Expense	$ 49,300	$ 49,300	$ -	
C-13	Worker's Compensation Expense	$ 21,020	$ 21,020	$ -	
C-14	Membership and Industry Association Dues	$ 16,498	$ 16,498	$ -	
C-15	Fleet Fuel Expense	$ 7,772	$ 32,199	$ (24,427)	Yes
C-16	Postage Expense	$ 15,979	$ 70,671	$ (54,692)	Yes
C-17	Interest Synchronization	$ 118,168	$ 118,085	$ 83	Yes
C-18	Corporate Cost Allocations	$ 7,838		$ 7,838	Added
C-19	Rate Case Expense	$ 70,612		$ 70,612	Added
C-20	CARES Related Amortization	$ 271,097		$ 271,097	Added
Total of Staff's Adjustments to Net Operating Income		$ 1,471,399	$ 1,235,516	$ 235,883	Yes
	Adjusted Net Operating Income per UNS Gas	$ 8,428,981	$ 8,428,981	$ -	
	Adjusted Net Operating Income per Staff	$ 9,900,380	$ 9,664,497	$ 235,883	Yes

- Based on a base rate revenue increase of $4.312 million, Staff proposes the revised rates shown on Attachment RCS-S1(R) to my surrebuttal testimony. The customer charge rates are the same as those contained in my supplemental testimony. The difference in the amount of base rate revenue increase has resulted in slightly lower volumetric charges than were proposed in my supplemental testimony.

- Staff's updated bill impact analysis relating to such rates is shown on Attachment RCS-S2(R) to my surrebuttal testimony.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who filed direct testimony in this case on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff")?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to respond to selected issues that were presented in the rebuttal testimony of UNS Gas, Inc. ("UNS GAS").

Q. What issues are addressed in your testimony?

A. My testimony addresses the company's proposed revenue requirement and rate design. I address Staff's adjustments to rate base and net operating income, and present a re-calculation of the revenue requirement and Staff's proposed rate design, based on information available at the time of the preparation of my surrebuttal testimony.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-2S contain the results of my analysis and presents Staff's updated revenue requirement.

Attachments RCS-S1(R) and RCS-S2(R) present Staff's updated rate design and bill impact analysis.

Q. How was your surrebuttal testimony on behalf of Staff impacted by outstanding discovery?

A. Staff had issued a set of discovery to UNS Gas (set 22) on March 22, 2007. The company's responses to that discovery could impact Staff's evaluation of some of the issues discussed in the UNS Gas rebuttal testimony. As of April 2, 2007, I have not yet received or had an opportunity to review UNS Gas' responses to those discovery requests. I received UNS Gas' initial partial responses to this set of Staff discovery on April 3, 2007. Staff will make the appropriate recommendations after it has had an opportunity to more thoroughly review UNS' responses.

II. REVENUE REQUIREMENT

Staff Recommendation

Q. What revenue increase does Staff recommend?

A. In Staff's Direct testimony, Staff recommended a revenue increase of $4.721 million. As a result of the adjustments discussed in my surrebuttal testimony, Staff recommends a revised revenue increase of $4.312 million, which is a reduction of $409,000. As shown on exhibit RCS-2S, schedule A, this is based on Staff's position that an adjusted weighted cost of capital should be applied to the FVRB. The comparable revenue increase that would be produced on the OCRB is $4.336 million.

Q. What revenue increase has been requested by UNS Gas?

A. UNS Gas is requesting a revenue increase of $9.647 million. In its rebuttal testimony, UNS Gas has agreed to a number of issues raised by Staff and RUCO. UNS Gas witness Dallas Dukes shows on his rebuttal exhibit DJD-1, page 3, that the company's proposed revenue requirement has been revised from the original request of $9.647 million downward to $9.487 million. However, the company continues to claim that its originally requested amount of $9.647 million is justified.

The Return Developed for Original Cost Rate Base Should Not Be Applied to Fair Value Rate Base Without Appropriate Adjustments

Q. How can UNS Gas still be claiming that it should receive the same amount of overall revenue increase that it originally requested, even after agreeing to some of the Staff and RUCO adjustments and showing a reduced revenue increase on rebuttal exhibit DJD-1?

A. One of the primary reasons for this is a new position advocated by the company in its rebuttal testimony: that the weighted cost of capital that was developed to apply to the original cost rate base should now be applied to the higher fair value rate base. At page 28 of his rebuttal testimony, UNS Gas witness Kentton Grant recommends:

"that the Commission apply the weighted cost of capital (or overall ROR) to the company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than proposed by the company, UNS Gas would still be limited to the original rate relief sought in the company's rate application."

Q. Is this new UNS Gas position consistent with the company's original filing?

A. No, it is not. In UNS Gas' own original filing, the company adjusted the return that is to be applied to fair value rate base downward, consistent with long-standing Commission practice, such that the revenue requirement produced by both the original cost rate base and the fair value rate base would not result in an excessive return on equity to the utility. UNS Gas' new position on this issue is also inconsistent with the way the return was applied to the fair value rate base in the current rate case filing of its affiliate, UNS Electric, in docket No. E-04204A-06-0783.

Q. What is the basis for this new position by UNS Gas?

A. According to Mr. Grant's rebuttal testimony, at page 28, the basis for this new position by UNS Gas is his "non-legal understanding of that ruling [i.e., a recent Arizona Court of Appeals ruling involving Chaparral city water company], is that the Arizona Court of Appeals found that Staff's determination of operating income ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona constitution."

Q. Does Staff agree with Mr. Grant's recommendation that, as a result of that ruling, the weighted cost of capital that was developed for use with an original cost rate base, should be applied without adjustment to the fair value rate base?

A. Absolutely not. Staff strongly disagrees with this recommendation by Mr. Grant for two reasons. First, the Court of Appeals, in the decision cited by Mr. Grant, specifically stated that the Commission was not bound to do what Mr. Grant is recommending. Page 9 of the Court of Appeals decision stated that: "Chaparral city ... asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chapparal City contends was done here." This is essentially the same recommendation being made by Mr. Grant in his rebuttal testimony in the current UNS Gas rate case. However, at page 13, paragraph 17, that Court of Appeals decision states as follows: "the Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct."

Thus, the Court of Appeals clearly stated that the Commission is not bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB.

Second, the methodology advocated by Mr. Grant (of applying the weighted cost of capital that was developed for use with an original cost rate base, without adjustment, to the FVRB) would tend to result in an unreasonable and excessive return on equity to the utility.

For these reasons, Staff strongly recommends that the methodology recommended by Mr. Grant be rejected.

Q. **What other guidance was provided in that Court of Appeals decision?**

A. At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "if the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. **How has Staff addressed the ruling in the Court of Appeals decision for purposes of the current UNS Gas rate case?**

A. In view of the Court of Appeals decision, Staff has appropriately adjusted the weighted cost of capital to the utility's fair value rate case. David Parcell's surrebuttal testimony describes Staff's position and response to the company's interpretation of the recent Chaparral decision. I would like to also point out, however, that the Chaparral decision is very recent and may still be the subject of further appeal. Further, Staff is still evaluating the decision.

On schedule D of Exhibit RCS-2S, I have derived the adjusted weighted cost of capital for application to the FVRB. On schedule A of that Exhibit I have applied Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his surrebuttal testimony. As shown on exhibit RCS-2S, Schedule A, the application of Staff's adjusted weighted cost of capital to the FVRB results in revenue increase of $4.312 million. In this instance, the application of the adjusted weighted cost of capital to the FVRB produces a slightly lower revenue requirement than does the application of the unadjusted rate of return to OCRB.

III. Rate base

Q. What rate base issues are you addressing in your surrebuttal?

A. I am addressing three rate base issues where there is a difference in the UNS Gas rebuttal position and the Staff recommendation:

- Exclusion of CWIP from rate base
- Exclusion of deferred GIS costs from rate base
- Cash working capital

With respect to the issue of exclusion of CWIP from rate base, I am also addressing the related proposal of UNS Gas for inclusion of post-test-year plant in rate base, and a new issue that was not raised by UNS Gas in its direct testimony, but which is being raised in its rebuttal testimony: the ratemaking treatment of customer advances.

Q. Have you prepared a schedule that updates Staff's proposed adjustments to rate base?

A. Yes. On Exhibit RCSs-2S, Schedule B, revised, Staff's adjustments to rate base have been updated for the impacts of issues described in my surrebuttal testimony. The Staff position on the exclusion of CWIP and deferred GIS costs from rate base has not changed as the result of UNS Gas' rebuttal testimony. As a result of changes to some of the adjustments to operating expenses, the working capital allowance amount has changed. The updated rate base reflects the change to the cash working capital allowance related to the expense changes.

B-1, Construction Work in Progress

Q. Please summarize UNS Gas' rebuttal concerning the company's proposal to include CWIP in rate base.

A. UNS Gas has proposed to include $7.189 million of construction work in progress ("CWIP") in rate base. UNS Gas witness Kentton Grant presents the following reasons for why the company believes CWIP should be included in rate base:

- While the rate base inclusion of CWIP is unusual in the sense that it has not been used for many years in Arizona, it is a tool available to the Commission for purposes of setting fair and reasonable rates.
- Two Arizona Supreme Court cases in the 1970s discussed the inclusion of CWIP in rate base and indicated that the Commission could consider it in determining rates.
- There are "extraordinary circumstances" in the current case justifying the inclusion of CWIP in rate base because Mr. Grant claims "it will be difficult, if not impossible, for the company to earn its authorized rate of return over the next several years."
- Inclusion of CWIP in rate base can be one means of addressing the "regulatory lag" issue for a utility with a large construction program.

- An extension of time between rate case filings could be beneficial to the company and its customers.

Basically, these are not new arguments for inclusion of CWIP in rate base, but rather are a restatement of the company's original request that CWIP be included in rate base in order to maintain the company's financial integrity, to mitigate regulatory lag, to fund its rapid growth and to extend the period between rate cases.

Q. **Mr. Grant's rebuttal testimony cites two Arizona Supreme Court cases in the 1970s that discussed the inclusion of CWIP in rate base. Has he demonstrated that the facts and circumstances of UNS Gas in the current case are similar to the specifics addressed in those cases?**

A. No.

Q. **Please comment upon the use of financial projections by Mr. Grant as support for his arguments that CWIP should be included in rate base.**

A. Mr. Grant appears to be relying on financial forecasts on pages 11-12 of his rebuttal. According to Mr. Grant, those forecasts show that the gap between the Company's embedded plant investment and incremental plant investment on a per-customer basis should narrow over time. Thus, the issue of regulatory lag should present less of a concern for the forecast period of 2007 through 2009 than it has for the historic period of august 2003 through December 2006. However, I would caution Against placing much reliance upon forecasts as the basis for ratemaking treatments, such as the CWIP issue in the current case. Forecasts are subject to change and can be inaccurate.

At pages 23-24 of his rebuttal testimony, Mr. Grant purports to recalculate his financial forecast and key financial indicators for UNS Gas based on inputting a $4.9 million reduction to the company's requested revenue increase. However, to merely input a revenue difference without also reflecting the impact of the specific adjustments which cause that difference (i.e., without also reflecting the reasons for the difference) is questionable and unlikely to produce reliable forecasts that are meaningful and relevant for ratemaking purposes. In states that utilize future test years, where projections are made beyond the historical period, adjustments are not just made to revenues but to all of the components of the ratemaking formula which impact the level of revenues. In jurisdictions that utilize future test years, when adjustments are made for disallowed expenses, the disallowed expenses are removed from the future test year. To the extent that Mr. Grant is attempting to use his revised financial forecasts as some kind of surrogate for a future test year, or as some kind of test of the reasonableness of the parties' differing recommendations, his comparisons do not appear to reflect the adjustments to rate base or expenses that contribute to Staff recommending a different level of revenue increase than has been requested by the company.

Q. Please discuss the issue of Regulatory Lag as it relates to the CWIP issue and to Utility Ratemaking in Arizona.

A. In Arizona, a historic test year with pro forma adjustments is used to establish utility rates. This approach has been employed for many years, and primarily without the inclusion of CWIP in utility rate base. The use of a test year, with appropriate adjustments, is intended to assure that the elements of the ratemaking formula are in balance. Regulatory lag refers to the difference in time between the test year and the rate effective date. My understanding is that it has always existed as an integral part of rate of return-based public utility regulation in Arizona, and for that matter virtually all states. It is not a new phenomenon which would require a change in basic regulatory policy. Moreover, there are other aspects of regulatory lag that benefit the company. These include expired amortizations and accumulated depreciation. The company continues to earn a return on and receives a recovery of assets that have already been recovered.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base.

Q. At page 26 of his rebuttal, Mr. Grant claims that your testimony does not describe what "burden of proof" UNS Gas would have to meet in order to have CWIP included in rate base. Please respond.

A. As I noted in my direct testimony, the burden of proof is on UNS Gas to prove its revenue requirement. Where the Commission has a very well-established policy, such as the exclusion of CWIP from rate base, UNS Gas must show convincingly that it is different in significantly important respects than the comparable circumstances in the other utility rate cases over the past decades where CWIP was excluded from rate base. In other words, UNS Gas must show how it is different from the normal circumstances of a regulated Arizona public utility where CWIP has been excluded from rate base. In the current case, UNS Gas has failed to do this.

In this case, UNS Gas, Staff and RUCO have all acknowledged that the Commission's policy and practice has been to exclude CWIP from rate base. My direct testimony presented a number of reasons why CWIP has been excluded from rate base, which apply to CWIP in general as well as to UNS Gas in the current case. Mr. Grant's rebuttal at page 26 does not refute these reasons. In fact, he indicates that two of the reasons are obvious: (1) that CWIP in rate base is not normally allowed by the Commission, and (2) that projects included in the test year CWIP balance were not in service as of the test year. He has also failed to demonstrate that post-test year revenue increases and expense reductions enabled by the CWIP have been properly identified and quantified by the company and used as an offset to the revenue requirement impact of including CWIP in rate base. The company's proposal fails the matching principle. Nor has Mr. Grant demonstrated that UNS Gas is in financial distress, that it cannot continue to attract capital at favorable terms if CWIP continues to be excluded from rate base, or that UNS Gas is different in terms of its customer growth and regulatory lag situation than the other major utilities in Arizona which do not have CWIP included in rate base.

Q. Based on your review of the reasons presented by UNS Gas in its direct and rebuttal testimony and other factors, should CWIP be included in rate base in the current case?

A. No. In general, Staff does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For the following reasons, Staff does not support UNS Gas' request for rate base inclusion of CWIP in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment. UNS Gas has not demonstrated that it is in financial distress, or that it would be unable to obtain financing at a reasonable cost if the normal practice of excluding CWIP from rate base is followed in the current case. Staff witness David Parcell addresses how Staff's recommendations should enable UNS Gas to continue to have access to financing at a reasonable cost. Mr. Parcell

addresses the determination of a fair rate of return that would allow UNS Gas to attract new capital on reasonable terms. In making his cost of capital recommendations, Mr. Parcell has been made aware of and has taken into consideration UNS Gas' proposal to include CWIP in rate base and Staff's recommendation that CWIP not be included in rate base in this case.

2) The CWIP was not in service at the end of the test year. As of December 31, 2005, the construction projects were not serving customers.

3) The company has not demonstrated that its December 31, 2005 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for mains, services and meters related to serving customer growth, i.e., to be revenue producing. Test year revenues have been annualized to year-end customer levels. However, revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced. Some of the facilities that are being constructed will be used subsequent to the 2005 test year to serve additional customers. It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process. Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test period. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed

in rate base unless there are very compelling circumstances which would warrant an exception to the general rule.

4) UNS Gas accrues a return, representing its financing costs during the construction period, called Allowance for Funds Used During Construction ("AFUDC"). This AFUDC return accounts for the utility's financing cost during the construction period.
5) Other large Arizona utilities are facing customer growth and similar "regulatory lag" issues to UNS Gas. Yet, to the best of my knowledge, none of the large Arizona utilities have CWIP in rate base. UNS Gas has failed to demonstrate that its circumstances are so different and unique that it requires a significantly different regulatory treatment for CWIP.

6) While the company has stated that inclusion of CWIP in rate base could result in deferring the filing of its next rate case, the company has made no specific enforceable commitments to a filing moratorium period.

In summary, in the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base.

Q. If CWIP were to be included in rate base, as requested by the company, what is the UNS Gas rebuttal position concerning whether the accrual of AFUDC should cease?

A. This issue is addressed in Mr. Grant's rebuttal at page 14. Mr. Grant recognizes that "the accounting guidelines published by the FERC require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals." However, he then attempts to carve out an exception for UNS Gas to this required accounting for AFUDC. He states that, because there is only a small amount of AFUDC on the test year balance of CWIP, it would be unfair to require UNS Gas to cease accruing AFUDC on $7.2 million of CWIP on an ongoing basis. He requests that, if the Commission grants the company's request to include CWIP in rate base, that language be included in the order that authorizes the company to continue accruing AFUDC on all eligible construction projects.

Q. Does Staff agree with this proposal by Mr. Grant to continue accruing AFUDC even if CWIP were to be included in rate base?

A. No. Mr. Grant's proposal to continue accruing AFUDC on CWIP should be rejected because it is contrary to the accepted accounting guidelines and would result in a double recovery of the financing cost of CWIP. The financing cost for CWIP can be addressed for ratemaking purposes in one of two ways: (1) through the inclusion of CWIP in rate base for a current cash return, or (2) through the accrual of AFUDC, which is added to the construction cost and is ultimately included in the cost of plant and depreciated. It would be improper to give UNS Gas both a cash return on CWIP through its inclusion in rate base and an AFUDC return. If CWIP were to be allowed in rate base, which the Staff is not recommending in this case, then AFUDC accruals on the amount of CWIP included in rate base must cease.

Q. Does Staff agree with UNS Gas' alternative proposal to include post-test year plant additions in rate base, if the inclusion of CWIP in rate base is denied?

A. No. Making the CWIP adjustment in a slightly different format, by adding post-test year plant into rate base, also suffers from the same flaws as the company's proposal to include CWIP in rate base. It is imbalanced because it fails to capture any post-test year revenue growth and maintenance decreases enabled by the new plant. Consequently, for similar reasons to the ones described above, Staff does not agree with UNS Gas' proposed alternative of including post-test year plant in rate base.

Q. At page 27 of his testimony, Mr. Grant recommends removing customer advances of approximately $4.158 million from rate base, if CWIP is excluded. Does Staff agree with this new UNS Gas proposal?

A. No. Customer advances should be reflected as a deduction from rate base. Customer advances represent non-investor supplied capital, and therefore should be reflected as a deduction to rate base. Mr. Grant has not cited any prior Arizona utility rate case in which CWIP was excluded from rate base and customer advances were not reflected as a reduction to rate base to recognize the non-investor provided cost-free capital. Nor is Staff aware of an instance for any major Arizona public utility where CWIP was excluded from rate base and customer advances were not reflected as a deduction to rate base. The Commission's rules (A.A.C. R14-2-103, appendix b, schedule B-1) require that customer advances be reflected as a deduction from rate base.

One additional reason why customer advances should be deducted from rate base is to prevent a double rate of return. In accruing AFUDC by applying the AFUDC rate to a CWIP balance, customer advances are typically not deducted from the construction cost base upon which AFUDC is computed. If the customer advances have not been specifically deducted in the AFUDC calculations (which would be contrary to the prescribed treatment for a utility following the AFUDC formula in the FERC uniform system of accounts), the non-investor provided cost-free capital in the form of customer advances needs to be reflected as a rate base deduction.

Consequently, the request by Mr. Grant to adjust the balance of customer advances, if CWIP is excluded from rate base, is contrary to precedent, would be improper for ratemaking purposes, and should be rejected.

B-2, Geographic Information System ("GIS") deferral

Q. Have you reviewed UNS Gas' rebuttal testimony concerning its request to include deferred GIS costs in rate base and to amortize such costs?

A. Yes. UNS Gas witness Dallas Dukes' rebuttal testimony, on pages 3-6, presents reasons why the company believes such deferred GIS costs should be included in rate base.

Q. At page 4, lines 17-18, Mr. Dukes states that: "the appropriate time to request an accounting order would have been in 2003, prior to beginning the project." Did UNS Gas request an accounting order at that time?

A. No. UNS Gas did not request an accounting order at that time or subsequently. UNS Gas is proposing that the Commission grant treatment as a "regulatory asset" of such costs in its current rate case. However, as explained in my direct testimony, Staff recommends that the company's requested "regulatory asset" treatment be rejected.

Q. Why does Staff disagree with UNS Gas concerning whether the GIS costs should be given "regulatory asset" treatment?

A. Because these expenditures are non-recurring expenses that were largely incurred prior to the test year, and because UNS Gas failed to request an accounting order at the appropriate time, Staff disagrees with the proposal by UNS Gas that the GIS costs be retroactively approved as a "regulatory asset" for inclusion in rate base and for the amortization of such an "asset" prospectively into customer rates.

Q. Mr. Dukes' rebuttal testimony refers to the GIS costs as an "investment." Do you agree with that characterization?

A. No. Under Generally Accepted Accounting Principles ("GAAP"), such costs were required to be expensed in the period incurred. The company had initially applied a capitalization treatment of such costs, but determined that that was an error and a violation of GAAP, and has recorded an entry on its books to expense such costs. For accounting purposes, the GIS costs are expenses, not an investment. The appropriate treatment for non-recurring expenses, especially ones relating to periods prior to the test year and for which deferral for accounting purposes was not pre-approved, is to exclude them from rates. Staff's proposed treatment does this.

Q. Is there an element of retroactive ratemaking in UNS Gas' request?

A. It appears so. The fact that the vast majority of the GIS expenses at issue here was incurred by UNS Gas prior to the 2005 test year, coupled with the fact that UNS Gas did not request and did not receive a timely accounting order from the Commission to defer such costs for consideration in a future rate case, does appear to contain elements of retroactive ratemaking. As I understand it, in the absence of a Commission accounting order authorizing such deferral, the prohibition Against retroactive ratemaking generally prevents utilities from deferring expenses incurred between rate cases for future recovery in rates.

Q. At page 6, item 5, of his rebuttal, Mr. Dukes' states: "if the company is not granted recovery of the investment, customers will reap the benefits of a system and the investors will have borne the cost without recovery." Please respond.

A. First, as noted above, the expenditures at issue are expenses under GAAP, not an investment. The company's own documents indicate that its initial attempt to account for this as an investment that would be capitalized was erroneous and did not comply with GAAP. Second, it is not uncommon or unusual for a utility's investors to be responsible for expenses which occur in between rate cases and to be responsible for expenses which are incurred outside of a test year. The flip-side to this is that, the utility's investors then also benefit from cost decreases and increased revenues that occur between rate cases. To the extent that the GIS system produces any cost savings that are not captured in the current test year, the utility's investors would benefit.

Q. At page 6 of his rebuttal testimony, Mr. Dukes claims that the GIS costs should receive regulatory asset treatment and prospective rate recovery "because of the GIS costs nexus to directly providing safe and reliable natural gas service to customers." Do these GIS costs require the special ratemaking treatment proposed by UNS Gas because they were incurred with some "nexus" to the provision of utility service?

A. No. The GIS costs that UNS Gas wants to include in rate base and amortize for prospective recovery are not really much different in substance than other expenses that UNS Gas recorded on its books prior to and during the test year. In any given year, UNS Gas has expenses that it records on its books that would also have a direct connection to providing safe and reliable natural gas service to customers. Examples of such costs would include costs for labor, outside services, depreciation, income taxes, other taxes, etc. Indeed, presumably the majority of UNS Gas' expenses in any particular year (other than disallowable items) have some type of "nexus" (direct or indirect) with the provision of utility service. However, without an accounting order pre-approving deferral treatment, it is inappropriate to defer such expenses into a future period. The mere connection between making expenditures that are recorded as expenses under GAAP in a particular year and the provision of utility service, does not in itself distinguish the GIS expenses from any other expenses which UNS Gas incurs which are related to the provision of safe and reliable utility service.

Q. Please summarize the reasons why the expenses related to the GIS should be excluded from rate base and why UNS Gas' request for prospective amortization into rates of such expenses should be denied.

A. UNS Gas' proposal to include $897,068 in rate base for a deferral of costs related to its GIS and its proposal to amortize such costs prospectively into rates should be denied for a number of reasons. The costs at issue were required to be expensed under GAAP.

Such expenses are of a one-time, non-recurring nature. Moreover, had it been expensed properly by UNS Gas in the appropriate periods when the expenditures were made, the vast majority of the GIS cost that UNS Gas deferred would have been expensed prior to the 2005 test year. UNS Gas did not request Commission pre-approval for recovery or cost deferral, and therefore could not defer the costs as a regulatory asset. Based on a review of the company's October 3, 2005 memo that was reproduced in attachment RCS-5 to my direct testimony, and the supporting documentation provided by UNS Gas, Staff concludes that the deferred GIS costs requested by UNS Gas are not an appropriate rate base item, do not qualify as a "regulatory asset," were not pre-approved for deferral by the Commission, are non-recurring costs that should have largely been expensed by the company in periods prior to the 2005 test year, and therefore are not appropriate to include in test year rate base. Accordingly, Staff adjustment B-2 has removed that amount of deferred costs from rate base, and Staff adjustment C-5 has removed the related company-proposed amortization.

B-3, Cash Working Capital

Q. Have the adjustments you have reflected in your surrebuttal testimony had an impact on the cash working capital allowance?

A. Yes. The cash working capital allowance has been updated for the impact of other adjustments. As shown on Exhibit RCS-2S, schedule B-3 revised, based on reflecting the impacts of Staff's adjustments, the revised working capital allowance for UNS Gas should be approximately negative $268,000.

IV. Adjustments to operating income

Q. Have you updated Staff's proposed adjustments to operating income?

A. Yes. Exhibit RCS-2S, Schedule C revised, page 1, summarizes Staff's recommended net operating income. Exhibit RCS-2S, Schedule C.1 revised, presents Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. These schedules reflect the acceptance of some adjustments described in UNS Gas' rebuttal testimony and/or modification to some of Staff's adjustments.

C-1, Revenue Annualization

Q. Please discuss the UNS Gas' rebuttal testimony concerning revenue annualization.

A. Mr. Erdwurm, at pages 4-7, of his rebuttal testimony claims that the "traditional approach" for customer annualization, which he indicates was applied in a fairly similar manner by both Staff and RUCO, is inappropriate in this case. Staff disagrees with Mr. Erdwurm and believes that the traditional approach to customer revenue annualization is appropriate for use in the current UNS Gas rate case.

Q. Mr. Erdwurm's rebuttal exhibit 1 shows that different annualization results would occur if a test year ending in a different month is selected. Does that invalidate the traditional approach to customer annualization for ratemaking purposes in this case?

A. No. Depending on the ending month of the test year, there would be variations under the traditional approach, or under the UNS Gas approach. The company selects the test year, so it has substantial control over which month would be the final month of the test year. The current test year ends December 31, 2005. Applying a customer annualization approach in the well-accepted traditional manner as Staff has done in the current case is not invalidated because a test year ending December 31, 2005 is being used.

Q. Is it necessary for the number of customers to grow in stair-step fashion for the traditional approach to be valid for ratemaking purposes?

A. No, it is not. What is important is that the growth that occurred during the test year is matched with the other elements of the ratemaking formula, including year-end plant in service, etc. The traditional method of customer annualization has been effective in appropriately coordinating the revenue element of the ratemaking formula with the other components, such as rate base.

Q. At page 5, lines 12-13, of his rebuttal, Mr. Erdwurm suggests that the traditional method works well when "new customers to be added after the test year have similar consumption to the average customer in the class (homogeneous customers)." How are new customers to be added after the test year considered in the annualization adjustment?

A. New customers added after the test year are not considered in the annualization adjustment. The annualization adjustment only considers customers that have been added during the test year, and annualizes only for customers that were added during the test year. Customers that are added after the end of the test year are typically not considered in an annualization adjustment, unless it is a major customer addition and the other elements of the ratemaking formula (rate base, depreciation, etc.) have been appropriately synchronized.

Q. At page 5, lines 22-26, of his rebuttal, Mr. Erdwurm asks the Commission to: "consider a hypothetical case where, a huge existing customer will plan to double its size, but at the same time a 'borderline' large customer is closing its doors. The impact of the huge customer's expansion may dwarf the loss of the entire borderline large customer. A huge positive customer annualization adjustment may be in order to recognize substantially higher revenue attributable to the huge customer's growth."

At page 6, lines 2-3, he concludes that: "the traditional approach is so easy; unfortunately it is sometimes overly simplistic and wrong." Has Mr. Erdwurm tied this hypothetical situation to the facts of the current UNS Gas rate case?

A. No.

Q. How does the hypothetical case of a huge customer discussed at page 5, lines 22-26, through page 6, line 3, of Mr. Erdwurm's rebuttal testimony apply to the specific customer annualization recommended by Staff in the current UNS Gas rate case?

A. Basically, it doesn't. Considering that the Staff's proposed revenue annualization is largely driven by small customers, including in particular residential and small commercial customer growth that occurred during the test year, Mr. Erdwurm's discussion of this hypothetical "huge customer" situation appears to totally miss the point of Staff's actual adjustment. Moreover, his hypothetical case provides no basis for an inference that the traditional method applied by Staff (and RUCO) in the current case to the UNS Gas specific customers, which are primarily residential and small commercial customers, is overly simplistic or wrong.

Q. **At page 6, lines 23-27, Mr. Erdwurm states that:**
"one cannot explain a negative adjustment – an adjustment that will increase customers' rates – on a growing system. Customers on a system with a positive growth trend in revenue, in customers, and in sales, should never pay more because of some negative customer adjustments calculated using a non-applicable traditional approach." Please respond.

A. First, this criticism appears to be misplaced in the context of the current rate case. Each party's (UNS Gas, Staff and RUCO's) revenue annualization adjustment reflects a net increase in test year revenues. Each parties' revenue annualization results in a net positive adjustment to test year revenues. So the issue of a negative revenue annualization adjustment, on an overall basis, is not an issue in the current case.

Second, Mr. Erdwurm's theory that a negative adjustment cannot be explained is incorrect. In both the UNS Gas filing and in Staff's annualization, a negative annualization adjustment (i.e., a pro forma revenue decrease) occurred for the rate group of large volume public authority customers. In UNS Gas' filing, the negative adjustment to revenue for this class was $17,185. In Staff's traditional revenue annualization calculation, the negative adjustment to revenue for this class was $13,212, for a difference of $3,973. Contrary to Mr. Erdwurm's theory that "one cannot explain a negative adjustment," there is a fairly simple explanation for this adjustment: the number of customers in the rate class decreased from 6 (during the period January through October

2005) to 5 (in November and December 2005). I should note that the impact of this negative adjustment for this rate class was largely offset by a positive adjustment for the large volume commercial customer class, where there was a change from 10 customers (during the period January through October 2005) to 11 (in November and December 2005). UNS Gas' annualization adjustment for that class added $11,351 in revenues and Staff's corresponding adjustment added $16,691, the net result for these two "large volume" classes between Staff and the UNS Gas revenue annualizations amounted to the Staff adjustments adding $1,367 more in net annualized revenue than the UNS Gas annualization adjustments for these rate classes. Moreover, a net difference in revenues of $1,367 between Staff and the company's proposed revenue annualizations for these two "large volume" rate classes certainly does not indicate any serious flaw or inaccuracy in Staff's use of the Commission's traditional annualization methodology in the current UNS Gas rate case.

Q. Are there any other considerations in determining an appropriate annualization method in a utility rate case?

A. Yes. The method should be straight-forward and transparent enough to enable the other parties to follow the calculations and results. This feature exists with respect to Staff's and RUCO's use of the traditional approach. In contrast, the calculations utilized by UNS Gas which applied percentage "growth factors" instead of customer bill counts, were difficult to follow in terms of verifying the percentages used, and appear to understate growth.

Q. Are you making any revisions to the Staff revenue annualization adjustment as the result of UNS Gas' rebuttal testimony?

A. No. Based on a reasonable review of the information presented in this case, the Commission's traditional annualization approach, which compares the customer counts in each month of the test year to the December 31, 2005 test year-end level of customers, and then multiplies the additional customers by the average revenue in each month (based on customer charges and average monthly usage volumes), is appropriate for use in the current UNS Gas rate case.

C-2, Weather Normalization

Q. Are differences between the Staff and UNS Gas related to the weather normalization adjustment dependent upon the revenue annualization?

A. Yes. Staff's weather normalization adjustment increases retail revenue by $1,962. Staff's adjustment varies from the weather normalization adjustment proposed by UNS Gas because the weighted average number of customers, in Staff's annualization, exceeded the corresponding level reflected in UNS Gas' corresponding annualization. Both the Staff and the UNS Gas weather normalization adjustments reflect an increase to revenue because the test year was warmer than normal.

Q. Are you making any revisions to the Staff weather normalization adjustment as the result of UNS Gas' rebuttal testimony?

A. No.

C-3, Bad Debt Expense

Q. Does Staff agree with the company's proposed amount of Bad Debt Expense?

A. No. However, the differences in bad debt expense between Staff and UNS Gas relate not to the calculation method, but rather are driven by the impact of the revenue adjustments. UNS Gas witness, Mr. Dukes, states at page 2 of his rebuttal that the differences in bad debt expense between UNS Gas and Staff result from the different customer annualization and weather normalization adjustments, and, other than that, UNS Gas and Staff are basically in agreement on the calculation. I agree with this assessment of the differences.

C-4, Remove Depreciation and Property Taxes for CWIP

Q. Has the UNS Gas rebuttal affected Staff adjustment C-4?

A. No. This adjustment removes the pro forma amounts calculated by UNS Gas for depreciation and property taxes related to the company's proposal to include CWIP in rate base. As explained above, Staff disagrees with that company proposal to include CWIP in rate base, and the company's alternative proposal to include post-test year plant in rate base.

C-5, Remove Amortization of Deferred GIS Cost

Q. Has the UNS Gas rebuttal affected Staff adjustment C-5.

A. No. This adjustment removes the company's proposed amortization of $299,023. As explained above in conjunction with Staff adjustment B-2, during 2003-2005, UNS undertook a project to locate and assign Global Positioning System ("GPS") information to its existing service lines in order to update the UNS Gas GIS. Part of the basis for this request by the company is that the project has a benefit to future periods. However, these expenses largely were incurred in prior periods and are nonrecurring. Without seeking

Commission pre-approval, UNS Gas is now requesting deferral treatment for costs that should have been expensed in periods prior to the test year.

As explained in my direct testimony, Staff agrees with the portion of UNS Gas' adjustment that removes the non-recurring GIS costs from test year O&M expense.

As explained above, in conjunction with adjustment B-2, and in my direct testimony, Staff disagrees, however, with the company's proposal to amortize such costs prospectively over a three-year period.

C-6, Incentive Compensation and Supplemental Executive Retirement Program

Q. Please respond to the company's rebuttal testimony concerning incentive compensation and SERP.

A. UNS Gas witness Dallas Dukes addresses these issues at pages 7-14 of his rebuttal testimony in terms of his rebuttal to Staff. He also presents fairly similar rebuttal testimony in response to RUCO's adjustments at pages 26-27 for incentive compensation and at pages 36 concerning SERP. Because Mr. Dukes' rebuttal on these issues is broken out by issue, I will respond to his rebuttal concerning the components of Staff adjustment C-6 by component.

Performance Enhancement Program ("PEP")

Q. Mr. Dukes asserts at page 7 of his rebuttal that the PEP program costs are a net savings to customers. Has he quantified the net savings to customers that were allegedly produced by PEP?

A. No.

Q. Mr. Dukes references benchmarking studies at page 9, line 3 of his rebuttal. Did he identify such studies by name or include them with his rebuttal testimony?

A. No. He did neither. Staff has requested such studies in discovery. However, responses to Staff set 22 have not been received as of the time of this writing.

Q. At pages 8-9 of his rebuttal, Mr. Dukes refers to the PEP compensation as being "at risk." Does this mean that, if goals specified in the plan are not achieved, the company then does not pay the compensation that is "at risk" under the PEP plan?

A. No. Even though the primary financial goal under the PEP was not met in 2005, incentive bonuses were paid. As explained in UNS Gas' supplemental response to STF 11.5(b):

"...the financial performance goal, which was a trigger under the PEP program for UNS electric, UNS Gas and Tucson Electric Power company ("TEP"), was not met. The financial performance goal was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the board of directors, the desire was to recognize employee achievements distinct from financial measures. The board deemed it appropriate to implement a special recognition award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the special recognition aware was paid at approximately 42% of the target for each of the operating companies."

These facts place into question how real the "at risk" feature of the PEP is in practice. Where retroactive changes can be and are made to alter the conditions under which incentive bonuses would be paid, this can result in incentive bonuses (or "at risk" compensation) being paid even when the specified goals per the terms of the PEP have not been met.

Q. Based on the information provided, do you see any meaningful distinction in the incentive compensation that was disallowed by the Commission in the recent southwest gas corporation rate case, and the incentive compensation that UNS Gas seeks to charge to rate payers in the current UNS Gas rate case?

A. No. As an illustrative example, in decision no. 68487, dated February 23, 2006, in a Southwest Gas Corporation ("SWG") rate case, the Commission adopted Staff's recommendation for an equal sharing of costs associated with that utility's management incentive plan compensation expense. In terms of whether the cost of the UNS Gas incentive compensation under the company's PEP plan should be similarly allocated between shareholders and ratepayers, I see no meaningful distinction in the UNS Gas situation that would require a different ratemaking treatment than the 50/50 sharing applied by the Commission in the SWG rate case.

Q. Please summarize why UNS Gas' Incentive Compensation Expense should be allocated 50/50 between shareholders and ratepayers.

A. UNS Gas' expense for incentive compensation should be allocated equally to shareholders and ratepayers because incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals. Moreover, there is no assurance that the award levels included in the company's proposed expense for the test year will be repeated in future years.

Tucson Electric Power company ("TEP") officer's long term incentive program

Q. Are you awaiting responses to discovery that was issued after receiving UNS Gas' rebuttal concerning the TEP officer's long term incentive program?

A. Yes. Until the responses to the discovery that was issued by Staff after UNS Gas' rebuttal are received and reviewed by Staff, the Staff recommendation concerning this compensation will remain unadjusted. After reviewing such responses, Staff will make appropriate recommendations at that time.

Unisource Energy Corporation Management and Directors Deferred Compensation Plan

Q. Are you awaiting responses to discovery that was issued after receiving UNS Gas' rebuttal concerning the Unisource Energy Corporation's Management and Directors Deferred Compensation Plan?

A. Until the responses to the discovery that was issued by Staff after UNS Gas' rebuttal are received and reviewed by Staff, the Staff recommendation concerning this compensation will remain unadjusted. After reviewing such responses, Staff will make appropriate recommendations at that time.

Supplemental Executive Retirement Plan ("SERP")

Q. Which UNS Gas rebuttal witness addresses Staff's proposed disallowance of SERP expense?

A. Mr. Dukes addresses the SERP at pages 12-14 of his rebuttal.

Q. At page 12, Mr. Dukes states that the amount identified for disallowance in the Staff adjustment "primarily represents benefit cost allocated to UNS Gas from TEP." Is that any reason for allowing SERP to be charged to ratepayers?

A. No. An expense that is otherwise disallowable should be disallowed whether it is incurred directly by the utility or is allocated to the utility from an affiliated company.

Q. At page 12, Mr. Dukes states that: "I recognize that Mr. Smith has at least partially relied upon [the] Commission's recent decision in the SWG rate case (Decision No. 68487) that disallowed the recovery of SERP expense." Has Mr. Dukes distinguished the TEP SERP from the Southwest Gas SERP sufficiently to require a different ratemaking treatment for UNS Gas than the one applied by the Commission for southwest gas in decision no. 68487?

A. I don't believe so. The factors cited by Mr. Dukes on pages 12-14 of his rebuttal testimony appear to be similar to the reasons that were presented by Southwest Gas in Docket No. G-0551A-04-0876, including that it is provided to officers, is to put the officers' retirement compensation on parity with other employees, and the reason for having the SERP is to provide additional retirement benefits to officers beyond the limits allowed in the IRS regulations for qualified retirement plans otherwise available to employees.

The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the company 401(k) contributions such that the company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Is Staff's recommendation to remove the UNS Gas SERP expense consistent with your understanding of recent Commission decisions that reached similar conclusions regarding the appropriate ratemaking treatment of incentive compensation and SERP expense?

A. Yes. As an illustrative example, in decision no. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted Staff's recommendation for an equal sharing of costs associated with that utility's management incentive plan compensation expense, and adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of decision no. 68487 that:

"although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to southwest gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."

Q. As a result of the UNS Gas rebuttal and information you received subsequent to the preparation of your direct testimony, are you making any revision to Staff adjustment C-6?

A. No.

Q. Did Staff request additional information on UNS Gas' Incentive Compensation and SERP?

A. Yes. As noted above, Staff data request set 22 was issued after reviewing UNS Gas' rebuttal testimony. I received UNS Gas' initial partial responses to that discovery on April 3, 2007. After Staff has an opportunity to thoroughly review the responses, Staff will make appropriate recommendations.

C-7, Emergency Bill Assistance Expense

Q. Is there any dispute between UNS Gas and Staff concerning adjustment C-7?

A. No. UNS Gas has accepted this Staff adjustment, which increases test year expense to be included in the base rate revenue requirement determination by $21,600 to provide for an increase requested by the company for emergency bill assistance.

C-8, Nonrecurring Severance Payment Expense

Q. As a result of the UNS Gas rebuttal, are you removing Staff adjustment C-8?

A. Yes. Staff adjustment c-8 was for a $52,388 severance payment for an employee who was terminated in 2004. This item was effectively adjusted to zero in the UNS Gas filing, so Staff adjustment c-8 is unnecessary.

C-9, Overtime Payroll Expense

Q. Has UNS Gas agreed with Staff adjustment C-9?

A. Yes. Page 17, lines 3-6 of Mr. Dukes' rebuttal testimony indicates that he agrees with this Staff adjustment, which reduced the amount of pro forma expense in the company's payroll adjustment, because it is more reflective of the expected overtime levels that should be included in rates.

C-10, payroll tax expense

Q. Are you revising Staff adjustment c-10?

A. Yes. This adjustment, which reduces test year payroll tax expense, is being revised for the impact of Staff's other adjustments to payroll, specifically for the removal of Staff adjustment C-8, for severance expense. As shown on Schedule C-10 revised, pro forma payroll tax expense is reduced by $9,348. This compares with the reduction to payroll expense of $13,356 that was presented with Staff's direct filing.

C-11, Nonrecurring FERC Rate Case Legal Expense

Q. Please discuss the company's rebuttal testimony concerning Staff adjustment C-11, for non-recurring legal expense.

A. Staff adjustment C-11 removed the substantial legal expenses related to settlement discussions in an El Paso natural gas rate case at the Federal Energy Regulatory Commission ("FERC") that UNS Gas incurred during the test year. Although that case has been settled, there is apparently going to be some level of ongoing expenses. At page 17, lines 19-21, of his rebuttal testimony, Mr. Dukes states that: "the objective should be to set legal expenses at a just and reasonable level that is reflective of how much is likely to be incurred annually." I agree in principle with this objective. UNS Gas witness dukes at pages 17-18 of his rebuttal testimony, however, then attempts to use an average of 2004 and 2005. Since the level of activity and legal expense in the FERC El Paso case could be significantly lower going forward than it has been during the historical period, I am not convinced that the backward-looking 2004-2005 average proposed by Mr. Dukes would represent "a just and reasonable level that is reflective of how much is likely to be incurred annually." In data request set 22, Staff asked UNS Gas for additional information on this issue. After reviewing the company's responses to that discovery (which I received on April 3, 2007), Staff will make the appropriate recommendations.

C-12, Property Tax Expense

Q. What does the Company's rebuttal state with respect to Staff adjustment C-12 for property tax expense?

A. Exhibit DJD-1, page 3 of 3, which was attached to Mr. Dukes' rebuttal testimony states that: "Staff & RUCO adjusted [property taxes] to match their plant in service and also reached out an additional year to 2007 for assessment rate reductions. UNS Gas disagrees with these adjustments." That Exhibit references Ms. Kissinger as the UNS Gas rebuttal witness for this issue. However, Ms. Kissinger's rebuttal testimony does not appear to offer any response to Staff adjustment C-12.

Q. Why is Staff adjustment C-12 necessary?

A. This adjustment is necessary to reflect the known statutory assessment ratio of 24 percent applicable for 2007. The Arizona state legislature passed House Bill No. 2779 which set a new rate schedule for property tax assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The company's calculation used a 24.5 percent assessment rate and thus fails to recognize the impact of this known tax change prospectively.

Q. How did Staff determine its recommended assessment rate?

A. The current assessment rate in 2007 is 24 percent. Staff concluded that since the Commission approved rates are expected to become effective in mid-2007, and the company's anticipated rate case interval is three years, as evidenced by the company's proposed normalization period for rate case expense, the property tax rate that will be in effect for 2007 of 24 percent is appropriate.

In terms of determining the recommended assessment rate, I also considered how Staff's recommendation in the current UNS Gas rate case compares with Staff's similar determination in the recent southwest gas rate case. This comparison is summarized in the following table:

In the Southwest Gas case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending august 31, 2004. As explained in my direct testimony and above, the appropriateness of using the known 24 percent assessment rate in the current UNS Gas rate case is supported by the comparison in the above table.

C-13, Worker's Compensation Expense

Q. Has UNS Gas accepted Staff adjustment C-13?

A. Yes. UNS Gas has accepted this Staff adjustment, which reversed a UNS Gas' proposed adjustment to increase test year expense for using a cash basis, rather than an accrual accounting basis, for recognizing worker's compensation expenses for ratemaking purposes.

C-14, Membership and Industry Association Dues

Q. What does UNS Gas' rebuttal testimony state with respect to American Gas Association ("AGA") dues?

A. Page 35 of UNS Gas witness Dallas duke's testimony states that the company accepts RUCO witness Rodney Moore's adjustment to AGA dues. Mr. Moore's direct testimony addressed this at pages 26-29. He recommended disallowing 3.64 percent of AGA dues based on an AGA/NARUC oversight committee report which had apparently identified 1.54 percent for dues allocated to marketing and 2.10 percent for lobbying. Accordingly, Mr. Moore reduced AGA dues expense by $1,523.

Q. Does Staff agree with that adjustment?

A. Not entirely. Staff agrees that the marketing and lobbying-related portion of the AGA dues should definitely be removed from rates. I also recognize that in the southwest gas rate case, decision no. 68487, at page 14, after having removed the portion of the AGA dues directly attributable to marketing and lobbying, southwest gas was found to have demonstrated that the remainder of the AGA dues should be recoverable as legitimate test year expenses. However, I also note the clear directive from the Commission at page 14 of that order that: "in its next rate case filing the company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the company and its Arizona ratepayers." While that directive applied to Southwest Gas, I believe it would have effectively put the other gas distribution utilities in the state who have AGA memberships on notice concerning the type of information the Commission would expect them to produce in a rate case in order to justify the inclusion of AGA dues in rates.

In the current rate case, UNS Gas has not produced such information. Staff asked UNS Gas discovery to try to obtain such information, and it was not provided by UNS Gas. As illustrative examples, the company's response to STF 5.62(c) stated: "the company did not receive any materials from the AGA specifying what percentage of their expenses is dedicated to lobbying or advocacy activities. UNS Gas has not excluded any portion of dues paid to the AGA during the test year." Similarly, the company's response to STF 5.62(b) stated: "UNS Gas does not maintain any descriptive material regarding the financial statements, annual budgets or activities of the AGA." Consequently, the company has not met its burden of proof for including AGA dues in rates, and Staff is asking the Commission to consider a larger disallowance of AGA dues in the current UNS Gas rate case than was proposed by RUCO witness Moore.

Specifically, Staff has proposed to reduce test year expense by $26,868, as shown on Schedule C-14 that was filed with my direct testimony. This adjustment removes 40 percent of UNS Gas' 2005 AGA dues for 2005, which were $41,854. Staff adjustment c-14 also removed other discretionary membership and industry association dues which are not needed for the safe and reliable provision of gas utility service.

Q. How did you determine the 40 percent disallowance for AGA dues?

A. As explained in my direct testimony, this was based upon a review of information in the two most recent National Association of Utility Regulatory Commissioners ("NARUC") sponsored audit reports of the expenditures of the American Gas Association. Copies of relevant pages from those audit reports are provided in attachment RCS-3 to my direct testimony.

I also included with my direct testimony, in attachment RCS-4, for the Commission's consideration, an excerpt from a Florida Public Service Commission Staff memorandum (dated 12/23/03) in a city gas company rate case addressing this issue, where 40% of that gas distribution utility's AGA dues amount was disallowed for ratemaking purposes.

C-15, Fleet Fuel Expense

Q. Have you revised Staff adjustment c-15?

A. Yes. This adjustment has been revised to reflect the amount shown in UNS Gas' rebuttal testimony.

C-16, Postage Expense

Q. Have you revised Staff adjustment C-16 for postage expense?

A. Yes. This adjustment was revised to use a starting point of $445,171 for the adjustment calculation. I have accepted that $445,171 is the appropriate starting point for the calculation, as discussed in Mr. Dukes' rebuttal testimony at pages 19-20. This produces an annualized postage expense of $476,960. An annualized postage expense of $476,960 properly recognizes the postage expense increase that occurred on January 8, 2006 and the customer growth that occurred during the 2005 test year.

Q. Are you aware of another postage rate increase?

A. Yes. Another postage rate increase has been approved by the U.S. Postal Service Board of Governors and is scheduled to take effect May 14, 2007. This increase would raise the cost of a first class letter from $0.39 to $0.41.

Q. If the postage rate increase to become effective May 14, 2007 were to be factored into the postage annualization, what would be the result?

A. If the postage rate increase to become effective May 14, 2007 were to be factored into Staff's calculation, the postage annualized postage expense would be $503,356 and the adjustment to the $529,380 amount in the UNS Gas filing would be a decrease of $26,024.

Q. Should the postage increase that is scheduled to become effective May 14, 2007 be reflected for ratemaking purposes?

A. This is a known change in the postage rate. In some respects, it is similar to a known change in a tax rate. As described in my direct testimony and above, Staff has reflected the known changes in the property tax assessment rate of 24 percent effective for 2007. Reflecting a known postage rate increase that becomes effective May 14, 2007 appears to be reasonably coordinated with the period covered by the known property tax assessment rate change used by Staff. Consequently, I have revised the Staff postage expense to $503,356 to incorporate the impact of this additional postage rate increase. This revised Staff adjustment on schedule C-16 reduces the UNS Gas proposed amount of $529,380 by $26,024.

Q. At page 20 of his rebuttal testimony, Mr. Dukes references what he calls a "known and measurable" amount of postage expense for 2006 and suggests that, because of that 2006 expense, the company's originally proposed postage request of $529,380 should be used. Does Staff agree with this analysis by Mr. Dukes?

A. No. The 2006 postage expense amount would reflect customer growth beyond the end of the test year, and the related revenues resulting from such customer growth beyond the end of the test year have not been reflected. As discussed in my direct testimony and above in conjunction with Staff adjustment C-1, customer growth has only been reflected through December 31, 2005, the end of the test year. Reflecting increased postage expense related to post-test year growth in the number of customers without reflecting the related additional revenues is inappropriate and should be rejected.

Q. Do you have any other observations on measures being implemented by the company that should mitigate increases in its postage expense prospectively?

A. Yes. The company has established an electronic billing option and expects an increasing number of customers to sign up for electronic billing. This should help mitigate increases in postage expense prospectively.

C-17, Interest Synchronization

Q. Was Staff's interest synchronization adjustment affected by other changes?

A. Yes. It was affected by the change in rate base. I have prepared a revised interest synchronization adjustment on schedule C-17 to reflect that change. This adjustment decreases income tax expense by the amount shown on schedule C-17 and increases the company's achieved operating income by a similar amount.

C-18, Corporate Cost Allocation

Q. Please explain the adjustment for Corporate Cost Allocation.

A. As described at page 24 of UNS Gas witness Dukes rebuttal testimony, RUCO discovered some additional non-recurring charges related to an attempted merger and has correctly proposed to remove such costs. UNS Gas agreed with that RUCO adjustment. Staff adjustment c-18 reflects Staff's agreement that such costs should be removed and reduces expense by $12,765 accordingly.

C-19, Rate Case Expense

Q. Please discuss the allowance for Rate Case Expense.

A. UNS Gas' original filing requested an amount of $600,000 for rate case expense normalized over a three year period, for an annual allowance of $200,000 per year. UNS Gas' rebuttal testimony requests that the annual allowance be increased to $300,000 per year. At page 34 of his rebuttal testimony, Mr. Dukes states that it is possible that the balance (of the company's rate case deferral account) may reach $900,000, which is $300,000 more than UNS Gas had originally budgeted. He attributes the high rate case cost to two factors: (1) that the organization is going through the first rate case for UNS Gas and is thus having to research and address all issues for the first time, and (2) the volume, complexity and magnitude of data requests from Staff, RUCO and other intervenors, which he states "was probably also as a result of this being the first rate case for UNS Gas." In his rebuttal testimony, Mr. Dukes requests that an amount of $300,000 per year be built into UNS Gas' base rates for rate case expense.

Q. Did RUCO address rate case expense?

A. Yes. In contrast with UNS Gas' position, RUCO witness Rodney Moore noted at pages 25-26 of his direct testimony that the annual allowance requested by UNS Gas for rate case expense of $200,000 per year was substantially higher than the amount allowed for southwest gas corporation and recommended an allowance of $83,667 per year, based on limiting the total amount to $251,000 over three years.

Q. Does the fact that this is the first rate case for UNS Gas justify a $900,000 rate case expense?

A. No. While the current case may be the first rate case for this utility operation under its current ownership, it isn't the first rate case for this utility. This gas utility had periodic, recurring rate cases under its prior ownership by citizens utilities. The transfer of ownership should not be an excuse for charging ratepayers for what appear to be excessive amounts of rate case cost.

Moreover, the current UNS Gas rate case is similar to and presents many of the same issues, such as a proposed revenue decoupling mechanism, revisions to the PGA Mechanism, etc., that were recently addressed by the Commission in Docket No. G-01551A-04-0876, a rate case involving the other large gas distribution utility in the state, Southwest Gas Corporation. Staff believes that the southwest gas case provides a reasonable benchmark for what a reasonable allowance for rate case cost should be in the current UNS Gas rate case.

Q. What does Staff recommend for the allowance for rate case expense for UNS Gas in this proceeding?

A. Staff recommends an annual allowance of $85,000 per year, based on a total of $255,000 normalized over three years. The total amount of rate case expense requested by UNS Gas which has now been increased to $900,000 and the annual allowance of $300,000 per year over a three-year period appears to be excessive and would represent an unreasonable burden on ratepayers. The amount of $900,000 requested by UNS Gas in its rebuttal is over 3.8 times as high as the amount of rate case expense allowed by the Commission in the southwest gas rate case, which was $235,000 in total, and which was normalized over a three-year period. Although southwest gas is a larger utility than UNS Gas, the current UNS Gas rate case has similarities to the southwest gas rate case in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company Staff. Staff adjustment c-19 reduces the $200,000 annual amount that was requested in the company's original filing for rate case expense by $115,000 to provide for an annual allowance of $85,000 per year.

C-20, Cares Program Deferred Balance Amortization

Q. Please explain the adjustment for Cares Program Deferred Balance Amortization.

A. This adjustment is addressed by Staff witness Julie McNeely-Kirwan. As described in her testimony, Staff recommends that UNS Gas cease deferral of costs related to the Cares Program effective with the date for new rates established in this case. Staff has recognized Cares Program discounts in Staff's proposed rate design. Staff also recognizes that UNS Gas has accumulated some deferred costs related to the cares program. Adjustment C-20 reflects Ms. McNeely-Kirwan's recommendation concerning how those accumulated deferred cares costs should be treated for ratemaking purposes.

V. Changes to rules and regulations

Q. Are there any remaining disputed issues between UNS Gas and Staff concerning revisions to rules and regulations?

A. No.

VI. Rate design

Q. What aspect of rate design do you address in your surrebuttal testimony?

A. I address Mr. Erdwurm's rebuttal testimony concerning the company's proposed increases to customer charges. Staff witness Steven Ruback is also addressing the company's rebuttal concerning the customer charge component of rates, the recovery of the revenue requirement through a combination of fixed and variable charges, and the company's proposed TAM.

Q. At page 12 of his rebuttal testimony, Mr. Erdwurm states that "one cannot tell from the direct testimony whether any serious cost of service based consideration was given by Staff and intervenors to the Company's customer charge proposals." How was the cost of service considered in Staff's rate design proposals?

A. The cost of service was considered as one factor, among others, including gradualism, value of service, public acceptability and other non-cost of service criteria. Cost of service is an important rate design criteria, but not the sole criteria. Staff has recognized that the UNS Gas cost of service supports an increase in customer charges, and has proposed to mitigate the large increases in customer charges proposed by UNS Gas, based on other factors such as estimated bill impacts and similar charges authorized by the Commission for other regulated utilities.

Q. At page 12 of his rebuttal testimony, Mr. Erdwurm states that the company has proposed to raise the residential customer charge to $17 per month, which is below the $26 that he claims is substantiated in the UNS cost of service study. At page 12 he also states that: "too often, innovative approaches are discarded by simply contending that they violate 'gradualism,' or that they will cause 'rate shock' or will not gain 'public acceptability.'" Please respond.

A. The UNS Gas proposals to drastically increase the customer charge component of rates should be rejected because it violates principles of gradualism and could cause "rate shock" and would therefore likely be unacceptable to the rate paying public. As I explained in my supplemental testimony, rate design is an art, not a strict mathematical exercise, and requires the application of informed judgment. The UNS Gas proposal to increase residential customer charges from the current $7.00 to $17.00 per month, an increase of 142 percent, does raise issues of rate shock. Accordingly, Staff recommends that a more gradual approach to raising the customer charge component of UNS Gas' base rates should be employed.

Q. At page 12 of his rebuttal, UNS Gas witness Pignatelli states: "I am not surprised that neither Staff nor RUCO fully endorse our proposed rate design. But I am surprised Staff and RUCO basically ignore the fact that under UNS Gas' current rate design, cold-weather customers – particularly high-use customers – subsidize warm-weather customers." Please respond.

A. First, it should be recognized that, for any conglomeration of customers with different usage characteristics into a rate class, the averaging process that is used to develop rates will affect some customers differently than others. This is an inherent characteristic of developing rates using averages. It does not, however, indicate that inappropriate subsidization has been or is occurring.

Second, contrary to such statements by Mr. Pignatelli, Staff has not ignored consideration of increasing the proportion of UNS Gas' base rate revenue requirement that is to be recovered through fixed charges. The Staff-proposed rates were developed specifically with one of the goals in mind of allowing UNS Gas to recover more of its revenue requirement through fixed charges. This is shown on attachment RCS-S1(R), schedule RD-4. For each rate class, with the exceptions of residential cares (R12) for which special low-income customer considerations apply, and for special gas lighting (p44) for which the cost is recovered 100 percent through customer charges, the proposed rates from customer charges represent a higher percentage of total base rate revenue for that rate class. Moreover, as shown on attachment RCS-S1(R), schedule RD-1, page 2, Staff has recommended increases in the fixed, customer charge portion of rates for all customer classes with the sole exception of the low-income cares rate.

Q. At page 12 of his rebuttal testimony, Mr. Pignatelli claims that "neither Staff's nor RUCO's proposals really get us significantly closer to sending accurate price signals." Please respond.

A. As shown on attachment RCS-S1(R), schedule RD-1, page 2, Staff has recommended increases in the customer charge portion of rates for all customer classes with the sole exception of the low-income cares rate. The UNS Gas proposals would, among other things, increase residential customer charges from the current $7.00 to $17.00 per month, for an increase of 142 percent. Considering the many factors that should be weighed in rate design, I believe that Staff's gradual approach of increasing customer charges is more appropriate than the UNS Gas proposals and, therefore, Staff's approach should be adopted in this case.

Q. Have you updated the Staff proposed rate design and bill analysis that was filed with your supplemental testimony to reflect the Staff's revised revenue requirement?

A. Yes. Attachment RCS-S1(R) to my surrebuttal testimony presents the Staff proposed rate design summary and proof of revenue (revised). Attachment RCS-S2(R) presents the bill impact analysis of Staff proposed rate design (revised).

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Attachment RCS-2S

Staff Accounting Schedules (Revised)

Accompanying the Surrebuttal Testimony of Ralph C. Smith

Schedule	Description	Pages	Revised
	Revenue Requirement Summary Schedules		
A	Calculation of Revenue Deficiency (Sufficiency)	1	Yes
A-1	Gross Revenue Conversion Factor	1	Yes
B	Adjusted Rate Base	1	Yes
B.1	Summary of Adjustments to Rate Base	1	Yes
C	Adjusted Net Operating Income	1	Yes
C.1	Summary of Net Operating Income Adjustments	4	Yes
D	Capital Structure and Cost Rates	1	Yes
	Rate Base Adjustments		
B-1	Remove Construction Work in Progress	1	
B-2	Remove GIS Deferral	1	
B-3	Cash Working Capital - Lead/Lag Study	1	Yes
B-4	Accumulated Deferred Income Taxes	1	
	Net Operating Income Adjustments		
C-1	Revenue Annualization	1	
C-2	Weather Normalization	1	
C-3	Adjustment to Bad Debt Expense	1	
C-4	Remove Depreciation & Property Taxes for CWIP	1	
C-5	Remove Amortization of Deferred GIS Cost	1	
C-6	Incentive Compensation and SERP	1	
C-7	Emergency Bill Assistance Expense	1	
C-8	Nonrecurring Severance Payment Expense	1	Yes
C-9	Overtime Payroll Expense	2	
C-10	Payroll Tax Expense	1	Yes
C-11	Nonrecurring FERC Rate Case Legal Expense	1	
C-12	Property Tax Expense	1	
C-13	Worker's Compensation Expense	1	
C-14	Membership and Industry Association Dues	1	
C-15	Fleet Fuel Expense	1	Yes
C-16	Postage Expense	1	Yes
C-17	Interest Synchronization	1	Yes
C-18	Corporate Cost Allocations	1	Added
C-19	Rate Case Expense	1	Added
C-20	CARES Related Amortization	1	Added
	Total Pages	35	

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule A

Revised

			UNS Proposed		Staff Proposed	
Line No.	Description	Reference	Original Cost (A)	Fair Value (B)	Original Cost (C)	Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 161,661,361	$ 191,177,715	$ 154,547,272	$ 184,063,625
2	Rate of Return	Sch. D	8.80%	7.44%	8.12%	6.81%
3	Operating Income Required		$ 14,223,179	$ 14,223,179	$ 12,549,238	$ 12,534,733
4	Net Operating Income Available	Sch. C	$ 8,428,981	$ 8,428,981	$ 9,900,380	$ 9,900,380
5	Operating Income Excess/Deficiency		$ 5,794,198	$ 5,794,198	$ 2,648,858	$ 2,634,353
6	Gross Revenue Conversion Factor	Sch. A-1	1.6649	1.6649	1.636969	1.636969
7	Overall Revenue Requirement		$ 9,646,901	$ 9,646,901	$ 4,336,098	$ 4,312,354

Notes and Source

Cols. A & B taken from UNS Gas, Inc. filing, Schedule A-1

UNS Gas, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule A-1
Page 1 of 1
Revised

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.51%	0.51052%
3	Taxable Income as a Percent	99.49%	99.48948%
4	Less: Federal and State Income Taxes	39.43%	38.40095%
5	Change in Net Operating Income	60.06%	61.08853%
6	Gross Revenue Conversion Factor	1.6649	1.636969

Notes and Source
Col.A: UNS Gas Inc. Filing, Schedule C-3
Col.B: Response to STF 5.76, item 6

Components of Revenue Requirement Increase

	Amount	Percent
Net Income	$ 2,648,859	61.09%
Federal and State Income Taxes	$ 1,665,103	38.40%
Uncollectibles	$ 22,137	0.51%
Total Revenue Increase	$ 4,336,099	100.00%

UNS Gas, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended December 31, 2005

Line No.	Description	Original Cost: As Adjusted by UNS (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)	RCND: As Adjusted by UNS (D)	RCND: Staff Adjustments (E)	RCND: As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 279,169,694	$ (7,189,231)	$ 271,980,463	$ 374,243,421	$ (7,189,231)	$ 367,054,190
2	Less: Accumulated Depreciation	$ (72,006,708)	$ -	$ (72,006,708)	$ (97,114,865)	$ -	$ (97,114,865)
3	Net Utility Plant in Service	$ 207,162,986	$ (7,189,231)	$ 199,973,755	$ 277,128,556	$ (7,189,231)	$ 269,939,325
4	Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -	$ -	$ -	$ -	$ -	$ -
6	Net Southern Union Acquisition Premium	$ -		$ -	$ -	$ -	$ -
7	*Citizens Acquisition Discount*	$ (30,709,738)	$ -	$ (30,709,738)	$ (41,822,562)	$ -	$ (41,822,562)
8	Less: Accum. Amort. - Citizens Acq. Discount	$ (1,876,981)	$ -	$ (1,876,981)	$ (2,560,308)	$ -	$ (2,560,308)
9	Net Citizens Acquisition Discount	$ (28,832,757)	$ -	$ (28,832,757)	$ (39,262,254)	$ -	$ (39,262,254)
10	Total Net Utility Plant	$ 178,330,229	$ (7,189,231)	$ 171,140,998	$ 237,866,302	$ (7,189,231)	$ 230,677,071
11	Customer Advances for Construction	$ (7,283,595)	$ -	$ (7,283,595)	$ (7,786,962)	$ -	$ (7,786,962)
							$ -
12	Customer Deposits	$ (3,040,484)	$ -	$ (3,040,484)	$ (3,040,484)	$ -	$ (3,040,484)
							$ -
13	Accumulated Deferred Income Taxes	$ (6,484,809)	$ 195,336	$ (6,289,473)	$ (6,484,809)	$ 195,336	$ (6,289,473)
14	Total Deductions	$ (16,808,888)	$ 195,336	$ (16,613,552)	$ (17,312,255)	$ 195,336	$ (17,116,919)
15	Allowance for Working Capital	$ (1,045,146)	$ 776,874	$ (268,272)	$ (1,045,146)	$ 776,874	$ (268,272)
							$ -
16	Regulatory Assets	$ 1,204,887	$ (897,068)	$ 307,819	$ 1,204,887	$ (897,068)	$ 307,819
							$ -
17	Regulatory Liabilities	$ (19,721)	$ -	$ (19,721)	$ (19,721)	$ -	$ (19,721)
18	Total Rate Base	$ 161,661,361	$ (7,114,089)	$ 154,547,272	$ 220,694,067	$ (7,114,089)	$ 213,579,978

Notes and Source
Cols. A and D: UNS Gas Inc. filing, Schedule B

Fair Value Calculation (Per Company)

Original Cost	$ 161,661,361	
RCND	$ 220,694,067	
Total	$ 382,355,428	
Average (Fair Value)	$ 191,177,715	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 154,547,272	
RCND	$ 213,579,978	
Total	$ 368,127,250	
Average (Fair Value)	$ 184,063,625	See Sch. A

UNS Gas, Inc.
Summary of Rate Base Adjustments

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B
Page 2 of 2
Revised

Line No.	Description	Staff Adjustments	CWIP B-1	GIS Deferral B-2	Cash Working Capital B-3 Revised	ADIT B-4	B-5	B-6
1	Gross Utility Plant in Service	$ (7,189,231)	$ (7,189,231)					
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (7,189,231)	$ (7,189,231)	$ -	$ -	$ -	$ -	$ -
4	Southern Union Acquisition Premium	$ -						
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -						
6	Net Southern Union Acquisition Premium	$ -						
7	Citizens Acquisition Discount	$ -						
8	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
9	Net Citizens Acquisition Discount	$ -						
10	Total Net Utility Plant	$ (7,189,231)	$ (7,189,231)	$ -	$ -	$ -	$ -	$ -
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Accumulated Deferred Income Taxes	$ 195,336				$ 195,336		
14	Total Deductions	$ 195,336	$ -	$ -	$ -	$ 195,336	$ -	$ -
15	Allowance for Working Capital	$ 776,874			$ 776,874			
16	Regulatory Assets	$ (897,068)		$ (897,068)				
17	Regulatory Liabilities	$ -						
18	Total Rate Base	$ (7,114,089)	$ (7,189,231)	$ (897,068)	$ 776,874	$ 195,336	$ -	$ -

UNS Gas, Inc.
Adjusted Net Operating Income

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C

Revised

Line No.	Description	As Adjusted by UNS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Gas Retail Revenues	$ 45,689,225	$ 104,395	$ 45,793,620
2	Other Operating Revenues	$ 1,480,303	$ -	$ 1,480,303
3	Total Operating Revenues	$ 47,169,528	$ 104,395	$ 47,273,923
	Operating Expenses			
4	Purchased Gas	$ 355,528	$ -	$ 355,528
5	Other O&M Expenses	$ 24,459,035	$ (900,969)	$ 23,558,066
6	Depreciation & Amortization	$ 7,220,392	$ (936,800)	$ 6,283,592
7	Taxes Other Than Income Taxes	$ 4,730,094	$ (261,724)	$ 4,468,371
8	Income Taxes	$ 1,975,498	$ 732,488	$ 2,707,986
9	Total Operating Expenses	$ 38,740,547	$ (1,367,004)	$ 37,373,543
10	Net Operating Income	$ 8,428,981	$ 1,471,399	$ 9,900,380

Notes and Source
Col. A: UNS Gas Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Stafff Adjustments	Revenue Annualization C-1	Weather Normalization C-2	Adjustment to Bad Debt Expense C-3	Remove Depreciation & Property Taxes for CWIP C-4	Remove Amortization of Deferred GIS Cost C-5
	Operating Revenues						
1	Gas Retail Revenues	$ 104,395	$ 102,433	$ 1,962			
2	Other Operating Revenues	$ -					
3	Total Operating Revenues	$ 104,395	$ 102,433	$ 1,962	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas	$ -					
5	Other O&M Expenses	$ (900,969)			$ 1,263		
6	Depreciation & Amortization	$ (936,800)				$ (196,266)	$ (299,023)
7	Taxes Other Than Income Taxes	$ (261,724)				$ (166,884)	
9	PRE-TAX OPERATING EXPENSES	$ (2,099,492)	$ -	$ -	$ 1,263	$ (363,150)	$ (299,023)
10	PRE-TAX OPERATING INCOME	$ 2,203,887	$ 102,433	$ 1,962	$ (1,263)	$ 363,150	$ 299,023
11	Income Taxes	$ 732,488	$ 39,537	$ 757	$ (487)	$ 140,169	$ 115,417
11	TOTAL OPERATING EXPENSES	$ (1,367,004)	$ 39,537	$ 757	$ 776	$ (222,981)	$ (183,606)
12	OPERATING INCOME	$ 1,471,399	$ 62,896	$ 1,205	$ (776)	$ 222,981	$ 183,606

Notes and Source
Combined Effective Tax Rate* 38.598%
* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Incentive Compensation and SERP	Emergency Bill Assistance Expense	Nonrecurring Severance Payment Expense	Overtime Payroll Expense	Payroll Tax Expense	Nonrecurring FERC Rate Case Legal Expense
		C-6	C-7	C-8 Revised	C-9	C-10 Revised	C-11
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (262,223)	$ 21,600	$ -	$ (123,010)		$ (311,051)
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes	$ (5,202)				$ (9,348)	
9	PRE-TAX OPERATING EXPENSES	$ (267,425)	$ 21,600	$ -	$ (123,010)	$ (9,348)	$ (311,051)
10	PRE-TAX OPERATING INCOME	$ 267,425	$ (21,600)	$ -	$ 123,010	$ 9,348	$ 311,051
11	Income Taxes	$ 103,221	$ (8,337)	$ -	$ 47,479	$ 3,608	$ 120,059
11	TOTAL OPERATING EXPENSES	$ (164,204)	$ 13,263	$ -	$ (75,531)	$ (5,740)	$ (190,992)
12	OPERATING INCOME	$ 164,204	$ (13,263)	$ -	$ 75,531	$ 5,740	$ 190,992

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Property Tax Expense	Worker's Compensation Expense	Membership and Industry Association Dues	Fleet Fuel Expense	Postage Expense	Interest Synchronization
		C-12	C-13	C-14	C-15 Revised	C-16 Revised	C-17 Revised
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses		$ (34,234)	$ (26,868)	$ (12,657)	$ (26,024)	
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes	$ (80,290)					
9	PRE-TAX OPERATING EXPENSES	$ (80,290)	$ (34,234)	$ (26,868)	$ (12,657)	$ (26,024)	$ -
10	PRE-TAX OPERATING INCOME	$ 80,290	$ 34,234	$ 26,868	$ 12,657	$ 26,024	$ -
11	Income Taxes	$ 30,990	$ 13,214	$ 10,370	$ 4,885	$ 10,045	$ (118,168)
11	TOTAL OPERATING EXPENSES	$ (49,300)	$ (21,020)	$ (16,498)	$ (7,772)	$ (15,979)	$ (118,168)
12	OPERATING INCOME	$ 49,300	$ 21,020	$ 16,498	$ 7,772	$ 15,979	$ 118,168

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Corporate Cost Allocations	Rate Case Expense	CARES Amortization
		C-18 Added	C-19 Added	C-20 Added
	Operating Revenues			
1	Gas Retail Revenues			
2	Other Operating Revenues			
3	Total Operating Revenues	$ -	$ -	$ -
	Operating Expenses			
4	Purchased Gas			
5	Other O&M Expenses	$ (12,765)	$ (115,000)	
6	Depreciation & Amortization			$ (441,511)
7	Taxes Other Than Income Taxes			
9	PRE-TAX OPERATING EXPENSES	$ (12,765)	$ (115,000)	$ (441,511)
10	PRE-TAX OPERATING INCOME	$ 12,765	$ 115,000	$ 441,511
11	Income Taxes	$ 4,927	$ 44,388	$ 170,414
11	TOTAL OPERATING EXPENSES	$ (7,838)	$ (70,612)	$ (271,097)
12	OPERATING INCOME	$ 7,838	$ 70,612	$ 271,097

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Capital Structure & Cost Rates

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule D

Revised

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	n/a	n/a	n/a	n/a
2	Long-Term Debt	$ 98,859	50.00%	6.60%	3.30%
3	Common Stock Equity	$ 98,859	50.00%	11.00%	5.50%
4	Total Capital	$ 197,718	100.00%		8.80%
	ACC Staff - Proposed				
5	Short-Term Debt	n/a	n/a	n/a	n/a
6	Long-Term Debt	$ 98,859	55.33%	6.60%	3.65%
7	Common Stock Equity	$ 79,804	44.67%	10.00%	4.47%
8	Total Capital	$ 178,663	100.00%		8.12%
9	Difference				-0.68%
10	Weighted Cost of Debt				3.65%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base				
11	Short-Term Debt	$ -	0.00%		0.00%
12	Long-Term Debt	$ 85,515,125	46.46%	6.60%	3.06%
13	Common Stock Equity	$ 69,032,147	37.50%	10.00%	3.75%
	Capital financing OCRB	$ 154,547,272			
14	Appreciation above OCRB not recognized on utility's books	$ 29,516,353	16.04%	0% [a]	0.00%
15	Total capital supporting FVRB	$ 184,063,625	100.00%		6.8100%

Notes and Source
Lines 1-4 taken from UNS Gas Inc. filing, Schedule D-1
Lines 5-8: Staff witness David Parcell
Lines 11-15, Col.A:

Fair Value Rate Base	$ 184,063,625	Schedule A
Original Cost Rate Base	$ 154,547,272	Schedule A
Difference	$ 29,516,353	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

UNS Gas, Inc.
Remove Construction Work in Progress

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (7,189,231)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Remove GIS Deferral

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	Remove GIS Deferral	$ (897,068)	A&B

Notes and Source
A: UNS Gas Filing, Schedule B-2, page 2, line 16
B: Testimony of Staff witness Ralph Smith

FERC Account 183

Docket No. G-04204A-06-0463
Schedule B-3
Page 1 of 1
Revised

UNS Gas, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 12/31/05

Line No.	Description (A)	FERC	Per UNS Gas Pro Forma Test Year Amount (A)	Ref	Staff Adjustments (B)	Staff Adjusted (C)	Expense Lag Days (D)	Net Lag Days (RevLag - Col. D) (E)	Lead/Lag Factor (Col. E/365) (F)	Cash Working Capital Required (Col. F X Col.C) (G)
	Operating Expenses:									
	Non-Cash Expenses -									
1	Bad Debts Expense	904	$ 722,634	1a	1,263	723,897				$ -
2	Depreciation	403/404	7,950,183	1.4a	(196,266)	7,753,917				-
3	Amortization	406	(729,791)	1.4b	(740,534)	(1,470,325)				-
4	Deferred Income Taxes		3,178,719			3,178,719				-
	Other Operating Expenses -									
5	Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	(123,010)	7,164,735	24.50	14.45	0.0396	283,724
6	Incentive Pay (UNSG Direct Employees)	Multi	257,895	3a	(63,430)	194,466	267.00	(228.05)	(0.6248)	(121,502)
7	Purchased Gas	Calc	78,101,248	4a	148,392	78,249,640	30.97	7.98	0.0219	1,714,759
8	Office Supplies and Expenses	921	1,365,974	1.2a	(1,275)	1,364,699	20.72	18.23	0.0499	68,098
9	Injuries and Damages	925	574,128	1.2b	(34,234)	539,894	64.75	(25.80)	(0.0707)	(38,171)
10	Pensions and Benefits	926	2,452,071	1.2c	-	2,452,071	54.66	(15.71)	(0.0430)	(105,439)
11	Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A.	4,570,692	6a	(198,794)	4,371,899	44.91	(5.96)	(0.0163)	(71,262)
12	Property Taxes	408	4,103,376	1.4c	(247,174)	3,856,202	213.00	(174.05)	(0.4768)	(1,838,637)
13	Payroll Taxes	408	537,877	1.4d	(14,550)	523,328	19.30	19.65	0.0538	28,155
14	Current Income Taxes		(1,203,222)		2,397,591	1,194,369	41.42	(2.47)	(0.0068)	(8,122)
15	Interest on Customer Deposits	431	170,459	1.4e	-	170,459	182.50	(143.55)	(0.3933)	(67,042)
16	Other Operations and Maintenance	Multi	7,501,807	X.	(481,490)	7,020,317	53.10	(14.15)	(0.0388)	(272,388)
17	Total Operating Expenses		116,841,795		446,491	117,288,286				
	Other Cash Working Capital Elements:									
18	Interest on Long-Term Debt		5,334,825		306,150	5,640,975	91.62	(52.67)	(0.1443)	(813,993)
19	Revenue Taxes and Assessments	Calc	$ 18,788,535	L.	(6,438,322)	12,350,213	76.25	(37.30)	(0.1022)	(1,262,192)
20	Total Cash Working Capital - Calculated									$ (2,504,012)
21	Total Cash Working Capital - Per UNS Gas Filing, Schedule B-5, page 3 of 3									(3,280,886)
22	Adjustment to Cash Working Capital									776,874

Notes and Source
UNS Gas filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Revenue Lag, in days 38.95
Col.B: Staff workpapers for CWC calculation

	Per Company	
ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas Lead/Lag Only	78,101,248	4a
ProForma Oper. Exp. To Tie Too - Excl Income Taxes	114,866,298	
Less: 1a, 1.4a, 1.4b, 2a, 3a, 4a, 1.2a, 1.2b, 1.2c, 6a, 1.4c, 1.4d, 1.4e	107,364,491	
Other O&M	$ 7,501,807	X.

Line 14, Col.C, Current income taxes:

Per UNS Gas	(1,203,222)	Col.A, line 14
Staff adjustments to net operating income statement	732,488	Schedule C
Income taxes for revenue increase	1,665,103	Schedule A-1
Total current income taxes for CWC calculation	1,194,369	

UNS Gas, Inc.
Accumulated Deferred Income Taxes

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B-4
Page 1 of 1

Line No.	Description	Account	Amount (A)	Reference
	Adjustment to ADIT:			
1	For GIS deferral that UNS Gas added to rate base that Staff has removed	283	$ 346,250	Note A
2	SERP	190	$ (86,506)	Note B
3	*Incentive Comp related ADIT*	190	$ (64,408)	Note B
4	Total adjustment to ADIT		$ 195,336	

Notes and Source

A UNS Gas workpaper "H1 - GPS Reg Asset"

B Staff has removed SERP from operating expenses and allocated incentive comp expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

	Account and Description	Per Books (1)	UNS Gas Adjustment (2)	UNS Gas Adjusted	Staff Adjustment
	Account 190				
5	SERP	$ 88,747	$ (2,241)	$ 86,506 a	$ (86,506) B
6	Incentive Comp - PEP	$ 27,840		$ 27,840	$ (13,920) (3)
7	Long Term Incentive Comp	$ 100,975		$ 100,975	$ (50,488) (3)
8	Incentive Comp related ADIT	$ 128,815		$ 128,815	$ (64,408)

(1) Response to Staf DR 5.36
(2) UNS Gas, ADIT workpapers
(2a) UNS Gas workpaper "Pro Forma ADIT - Account 190" "SERP 12 D"
('3) Staff adjustment reflects a 50/50 allocation of incentive compensation responsibility between ratepayers and shareholders

UNS Gas, Inc.
Adjustment to Annualize Gas Retail Revenue

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-1

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Annualize Gas Retail Revenue	$ 725,682	A
2	Staff Recommended Annualized Gas Retail Revenue	$ 828,115	B
3	Adjustment to Annualized Gas Retail Revenue	$ 102,433	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 1, line 1

B: Total annualization adjustments calculated for the rate classes shown Schedules C-1.1, C-1.2 and C-1.3

FERC 480

UNS Gas, Inc.
Adjustment to Weather Normalization

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-2
Page 1 of 1

Line No.	Rate Class	UNS Gas Margin Weather Adjustment	Ratio of Weighted Average Annualized Customers	Staff Margin Weather Normalization	Adjustment to UNS Gas Proposed Weather Normalization
		(A)	(B)	(C)	(D)
1	Residential - 10	$ 369,269	1.004	$ 370,746	$ 1,477
2	Residential CARES - 12	$ 14,574	0.982	$ 14,312	$ (262)
3	Small Volume Commercial - 20	$ 95,408	1.009	$ 96,267	$ 859
4	Large Volume Commercial - 22	$ 67	1.000	$ 67	$ -
5	Irrigation - 60	$ 44	-	$ 44	$ -
6	Small Volume Public Authority - 40	$ 37,438	0.997	$ 37,326	$ (112)
7	Large Volume Public Authority - 42	$ 121	1.000	$ 121	$ -
8	Total	$ 516,921		$ 518,883	$ 1,962

Notes and Source

Col. A: UNS Gas proposed weather normalization adjustment
Col. B: Weighted average of Staff recommended annualized customers and UNS proposed annualized customers
Col. C: Col. A x Col. B
Col. D: Col. C - Col. A

FERC 480

UNS Gas, Inc.
Adjustment to Bad Debt Expense

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Bad Debt Expense	$ 317,758	A
2	Recommended Staff Adjustment to Bad Debt Expense	$ 319,021	
3	Adjustment to Bad Debt Expense	$ 1,263	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 5

B: Per Company's workpapers showing calculation of Bad Debt Expense adjustment (except where noted)

		UNS Gas Bad Debt Adj.	Staff Bad Debt Adjustment	
4	Test Year Revenues	$ 136,799,000	$ 136,799,000	
5	Add: Late Fees and Miscellaneous Service Revenues	$ 1,446,000	$ 1,446,000	
6	Total	$ 138,245,000	$ 138,245,000	
	Rate Case Adjustments			
7	Customer Annualization	$ 1,680,578	$ 1,687,027	A
8	Weather Normalization	$ 1,826,135	$ 2,067,072	B
9	Reclass Related to Prior Periods (CARES Adjustment)	$ (203,181)	$ (203,181)	
10	Total Rate Case Adjustments	$ 3,303,532	$ 3,550,918	
11	Uncollectible Revenue Adjustment Base	$ 141,548,532	$ 141,795,918	L6 + L10
12	2 Year Average Retail Write Off Rate	0.51052%	0.51052%	
13	Pro Forma Bad Debt Expense	$ 722,634	$ 723,897	L11 x L12
14	Recorded Test Year Bad Debt Expense	$ 404,876	$ 404,876	
15	Staff Recommended Adjustment to Bad Debt Expense	$ 317,758	$ 319,021	L13 - L14
	Note A			
	Weather			
	Normalization			
16	Revenue	$ 516,921	$ 518,883	Sch. C-2
17	Gas Cost	$ 733,104	$ 735,952	Staff workpaper
18	PGA	$ 430,554	$ 432,192	Staff workpaper
19	Total	$ 1,680,579	$ 1,687,027	
	Note B			
	Customer			
	Annualization			
20	Revenue	$ 725,682	$ 828,115	Sch. C-1
21	Gas Cost	$ 712,128	$ 795,387	Staff workpaper
22	PGA Adjustor	$ 388,325	$ 443,570	Staff workpaper
23	Total	$ 1,826,135	$ 2,067,072	

FERC Account 904

UNS Gas, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (196,266)	A&B
2	CWIP Related Property Taxes	408	$ (166,884)	A&B
3	Total Adjustments		$ (363,150)	

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 4, lines 6 and 7
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Remove Amortization of Deferred GIS Cost

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Remove Company-proposed Amortization of Deferred GIS Cost	407	$ (299,023)	A

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 6

B: Amounts taken from UNS Gas Workpaper for GIS expenditures adjustment

FERC Account 874	Per UNS Workpaper	2005 Cost		Pre-2005 Cost
Materials & Supplies	$ (505)	$ -		$ (505)
Outside Services - Consultants	$ (746,792)	$ 133,238	*	$ (613,554)
Property Tax	$ (60)	$ -		$ (60)
Travel - Meals & Entertainment	$ (265)	$ 51		$ (214)
Pensions & Benefits Allocated	$ (6,994)	$ 688		$ (6,306)
Worker's Compensation	$ (14)	$ 2		$ (12)
Payroll Taxes - FICA	$ (2,312)	$ 198		$ (2,114)
Payroll Taxes - Unemployment	$ (366)	$ 50		$ (316)
Vacation & Sick Accrual	$ (563)	$ 563		$ 0
Wages - Regular	$ (32,074)	$ 3,452		$ (28,622)
Wages - Overtime	$ (2,138)	$ -		$ (2,138)
FERC 874 Total	$ (792,083)			$ (653,840)
FERC Account 920				
A&G Expense Transferred - UNSG	$ (22,922)	$ 400		$ (22,522)
A&G Expense Transferred - TEP	$ (25,362)	$ 3,108		$ (22,254)
FERC 920 Total	$ (48,284)			$ (44,775)
FERC 874 and 920 Total	$ (840,367)			$ (698,616)

* 2005 expenditures derived from Frontline Energy Services LLC invoices provided in response to RUCO 2.15

UNS Gas, Inc.
Incentive Compensation and SERP

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-6

Revised

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Program (PEP)	$ (63,430)	A
2	Staff Adjustment to UES's Other Incentive Comp and SERP	$ (198,794)	B
3	Total Adjustment to Incentive Compensation Expense	$ (262,223)	
4	Adjustment to Taxes Other Than Income	$ (5,202)	B

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
874	Distribution - Mains & Services Expense	$ 20,731	50%	10,366
878	Distribution - Meter Expense	$ 16,844	50%	8,422
887	Distribution - Maintenance of Mains	$ 12,957	50%	6,479
903	Customer Records/Collections Expense	$ 29,800	50%	14,900
920	Administrative & General Salaries	$ 46,527	50%	23,264
		$ 126,859		$ 63,430
408	Taxes Other Than Income Taxes	$ 10,403	50%	5,202

B: Per UNS Gas Inc.'s response to STF 5.72

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
923	Supplemental Executive Retirement Plan (SERP)	$ 93,075	100%	$ 93,075
923	Officer's Long Term Incentive Plan	$ 108,920	50%	$ 54,460
923	Officer Portion of Performance Enhancement Plan (PEP)	$ 52,860	50%	$ 26,430
923	Deferred Compensation Plan	$ 11,315	50%	$ 5,658
923	Omibus Plan	$ 38,342	50%	$ 19,171
	Total	$ 304,512		$ 198,794

UNS Gas, Inc.
Emergency Bill Assistance Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-7
Page 1 of 1

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense		$ 21,600	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

UNS Gas, Inc.
Nonrecurring Severance Payment Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-8

Revised

Line No.	Description	Amount	Account	Reference
1	Adjustment to Remove Severance Accrual Adjustment	$ -	857	A

Notes and Source

A: UNS Gas workpapers used to calculate its payroll adjustment

UNS Gas, Inc.
Overtime Payroll Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-9

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Overtime Expense	$ 1,070,133	A
2	Staff Recommended Overtime Expense	$ 947,123	B
3	Adjustment to Overtime Expense	$ (123,010)	L2 - L1

Notes and Source

A: UNS Gas workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

Line No.	Description	2004	2005	2 Year Average
4	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
5	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
6	Total Overtime Charged Directly to O&M	$ 781,386	$ 1,000,445	$ 890,915
7	Regular Annualized O&M Payroll	$ 5,472,931		
8	Adjusted 2005 Regular O&M Wages per Books	$ 5,148,145		
9	Increase to Regular O&M Payroll	1.06309		
10	Two Year Average Overtime Charged to O&M	$ 890,915		
11	Increase to Regular Payroll	1.06309		
12	Staff Recommended Increase to Overtime	$ 947,123		

UNS Gas, Inc.
Adjustment to Overtime Payroll Expense - Alternative Calculation

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Total Overtime	$ 1,402,549	A
2	Staff Normalized Total Overtime	$ 1,220,536	B
3	Difference	$ (182,013)	L2 - L1
4	O&M Percentage	0.7630	C
5	Alternative Adjustment to Overtime Expense	$ (138,876)	

Notes and Source

A: UNS Gas workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
6	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
7	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
8	Overtime Charged to Non-O&M Accounts	$ 211,113	$ 303,260	$ 257,187
9	Total Overtime Charged Directly to O&M	$ 992,499	$ 1,303,705	$ 1,148,102

10	Regular Annualized O&M Payroll	$ 8,868,400
11	Adjusted 2005 Regular O&M Wages per Books	$ 8,342,113
12	Increase to Regular O&M Payroll	1.06309
13	Two Year Average Overtime Charged to O&M	$ 1,148,102
14	Increase to Regular Payroll	1.06309
15	Staff Recommended Increase to Overtime	$ 1,220,536

C:

16	Normalized Overtime Charged to O&M per Company	$ 1,070,133
17	Total Normalized Overtime per Company	$ 1,402,549
18	Percentage of Overtime Charged to O&M	0.7630

UNS Gas, Inc.
Payroll Tax Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-10

Revised

Line No.	Description	Amount	Reference
1	Adjustment Related to Severance Related Payroll Tax	$ -	A
2	Adjustment to Reduce Overtime Related Payroll Tax	$ (9,348)	B
3	Total Adjustment to Payroll Tax	$ (9,348)	

Notes and Source

A:	**Severance Accrual Adjustment (Schedule C-8)**		
4	Severance Accrual Adjustment	$ 52,388	
5	OASDI Tax Rate	6.20%	
6	OASDI Payroll Tax Related to Severance Adjustment	$ 3,248	
7	Severance Accrual Adjustment	$ 52,388	
8	Medicare Tax Rate	1.45%	
9	Medicare Payroll Tax Related to Severance Adjustment	$ 760	
10	OASDI Payroll Tax Related to Severance Adjustment	$ 3,248	
11	Medicare Payroll Tax Related to Severance Adjustment	$ 760	
12	Total Severance Related Payroll Tax Adjustment	$ 4,008	L6 +L9
B:	**Overtime Adjustment (Schedule C-9)**		
13	Overtime Payroll Adjustment	$ 123,010	
14	Allocator of wages in excess of $94,200	0.00817 *	
15	Wages in excess of $94,200	$ 1,005	L13 x L14
16	Overtime Payroll Adjustment	$ 123,010	
17	Wages in excess of $94,200	$ 1,005	
18	OASDI Tax Base	$ 122,005	L16 - L17
19	OASDI Tax Rate	6.20%	
20	OASDI Payroll Tax Related to Overtime Adjustment	$ 7,564	
21	Overtime Payroll Adjustment	$ 123,010	
22	Medicare Tax Rate	1.45%	
23	Medicare Payroll Tax Related to Overtime Adjustment	$ 1,784	
24	Adjustment to Overtime Related Payroll Tax	$ 9,348	L20 + L23

* Allocator of wages in excess of $94,200 calculated as follows:

Amounts taken from UNS Gas Payroll Tax adjustment workpaper

25	UNS Gas Unclassified Payroll in excess of $94,200	$ 83,916	
26	Gross Annualized Payroll - per Company	$ 10,270,949	
27	Allocator of wages in excess of $94,200	0.00817	L25 / L26

FERC 408

UNS Gas, Inc.
Nonrecurring FERC Rate Case Legal Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-11

Revised

Line No.	Description	Amount	Reference
1	Adjustment to FERC Rate Case Legal Expense	$ (311,051)	A

Notes and Source

A: Per UNS Gas Inc.'s response to STF 5.91

El Paso Gas Allocation/Rate Case settlement negotiations through law firm of Fleischman & Walsh LLP

	Invoice Amount
May 2005	$ 87,269
August 2005	$ 28,463
September 2005	$ 56,612
October 2005	$ 32,331
November 2005	$ 28,712
December 2005	$ 39,129
December 2005	$ 38,535
	$ 311,051

FERC Account 923

UNS Gas, Inc.
Property Tax Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-12

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Increase to Property Tax Expense	$ 1,591,370	A
2	Staff Proposed Increase to Property Tax Expense	$ 1,511,080	B
3	Adjustment to Property Tax Expense	$ (80,290)	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 5, line 7
B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

	Utility Plant in Service Taxes	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 12,668,650	$ 148,702,079	$ 9,770,270	$ 171,140,999
5	Less: Licensed Transportation in Rate Base	$ -	$ -	$(3,224,086)	$ (3,224,086)
6	Less: Land Cost & Rights of Way in Rate Base	$ (69,665)	$ (200,495)	$ (144,835)	$ (414,995)
7	Less: Environmental Property in Rate Base	$ (553,351)	$ (2,868,087)	$ (345,452)	$ (3,766,890)
8	Plus: Land FCV Per Arizona Dept. of Revenue		$ 697,806		$ 697,806
9	Plus: Materials & Supplies in Rate Base		$ 2,039,798		$ 2,039,798
10	Plant in Service Full Cash Value	$ 12,045,634	$ 148,371,101	$ 6,055,897	$ 166,472,632
11	Assessment Ratio*	24.0%	24.0%	24.0%	24.0%
12	Taxable Value	$ 2,890,952	$ 35,609,064	$ 1,453,415	$ 39,953,431
13	Average Tax Rate	9.4747%	9.4747%	9.4747%	9.4747%
14	Property Tax	$ 273,909	$ 3,373,852	$ 137,707	$ 3,785,468
15	Environmental Property in Rate Base	$ 553,351	$ 2,868,087	$ 345,452	$ 3,766,890
16	Statutory Full Cash Value Adjustment	50%	50%	50%	50%
17	Environmental Full Cash Value	$ 276,676	$ 1,434,044	$ 172,726	$ 1,883,445
18	Assessment Ratio*	24.0%	24.0%	24.0%	24.0%
19	Taxable Value	$ 66,402	$ 344,171	$ 41,454	$ 452,027
20	Average Tax Rate	9.4747%	9.4747%	9.4747%	9.4747%
21	Property Tax	$ 6,291	$ 32,609	$ 3,928	$ 42,828
22	Total Property Taxes	$ 280,200	$ 3,406,461	$ 141,635	$ 3,828,296
23	Property Taxes on Leased Property	$ -	$ -	$ 25,629 a	$ 25,629
24	Total Property Tax Expense	$ 280,200	$ 3,406,461	$ 167,264	$ 3,853,925
25	Less: Recorded Property Taxes Excluding Call Center	$ (135,825)	$ (2,082,996)	$ (124,024)	$ (2,342,845)
26	Property Tax Expense Adjustment	$ 144,375	$ 1,323,465	$ 43,240	**$ 1,511,080**

a: Property Tax for Leases calculated as follows (amounts taken from Company workpaper)

		Primary Value	Secondary Value	Total
	Cottonwood Lease			
27	Full Cash Value	$ 795,459	$ 1,016,515	
28	Assessment Ratio*	24.0%	24.0%	
29	Taxable Value	$ 190,910	$ 243,964	
30	Tax Rate	8.7284%	1.8218%	
31	Property Tax	$ 16,663	$ 4,445	$ 21,108
	Nogales Lease			
32	Full Cash Value	$ 397,182		
33	Assessment Ratio*	24.0%		
34	Taxable Value	$ 95,324		
35	Tax Rate	11.8563%		
36	Property Tax	$ 11,302		
37	*Percentage Allocated to UNS Gas*	40%		
38	Property Taxes Allocated	$ 4,521		$ 4,521
39	Total Lease Taxes			$ 25,629

* 2007 Arizona Statutory Assessment Ratio 24.0%

FERC 408

UNS Gas, Inc.
Worker's Compensation Expense

Docket No. G-04204A-06-0463
Schedule C-13

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Adjustment to Worker's Compensation Expense	925	$ (34,234)	A&B

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 2, line 5
B: Testimony of Staff witness Ralph Smith

FERC 925

UNS Gas, Inc.
Membership and Industry Association Dues

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-14

Line No.	Vendor	Amount	FERC Account
1	American Gas Association	$ 41,854	930
2	Less 40% Related to Lobbying & Advertising*	40%	
3	Adjusted American Gas Association	16,742	930
4	Arizona Utility Group	$ 500	930
5	Arizona Utility Investors Association	$ 2,500	930
6	Chino Valley Area Chamber of Commerce	$ 215	930
7	Coconino County Clerks of Superior Court	$ 18	921
8	Exchange Club	$ 375	921
9	Flagstaff Chamber of Commerce	$ 2,378	921
10	IBA Publishing Inc.	$ 325	930
11	Kingman Chamber of Commerce	$ 386	921
12	Kingman Rotary Club	$ 458	921
13	Mayer Area Chamber of Commerce	$ 72	930
14	Prescott Chamber of Commerce	$ 386	930
15	Prescott Valley Chamber of Commerce	$ 550	930
16	Seligman Chamber of Commerce	$ 40	930
17	Show Low Girls Soccer Booster Club	$ 25	930
18	Show Low Main Street	$ 375	930
19	U.S. Mexico Border Counties Coalition	$ 250	921
20	USDA Forest Service	$ 173	930
21	White Mountain Regional Development Corp.	$ 1,100	930
22	Total Membership and Industry Association Dues	$ 26,868	

Line No.		Total From Above	Adjustment
23	Total Amount Recorded in Account 921	$ 23,003	$ (23,003)
24	Total Amount Recorded in Account 930	$ 3,865	$ (3,865)
25	Total	$ 26,868	$ (26,868)

* Percentage derived from NARUC Audit Reports on AGA Expenditures for 1998 and 1999 issued January 2000 and June 2001, respectively

UNS Gas, Inc.
Fleet Fuel Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-15

Revised

Line No.	Description		Amount	Reference
1	UNS Gas Adjustment to Fleet Fuel Expense	$	73,726	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$	61,069	B
3	Adjustment to Fleet Fuel Expense	$	(12,657)	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 9

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment (except where noted)

4	Average operational FTE count for 2005		123.58	
5	Average technical FTE count for 2005		24.83	
6	Average construction FTE's for 2005		148.42	L4 + L5
7	2005 miles driven		2,228,658	
8	2005 mileage per Average Construction FTE		15,016	L7 / L6
9	2 month Average Construction FTE's for 2006		158	
10	Assumed 2006 mileage with 1st quarter staffing levels		2,365,055	L8 x L9
11	2005 Actual miles/gallon		9.60	
12	Calculated gallons purchased		246,360	L10 / L11
13	Average cost of fuel for November 2006 through January 2007	$	2.48	Note C
14	Cost of calculated gallons purchased	$	610,973	L12 x L13
15	Dollars purchased through Pro-Cards during 2005	$	37,491	
16	Pro forma fuel expenditures	$	648,464	L14 + L15
17	Test year expenditures	$	565,263	
18	Pro forma expenditure adjustment	$	83,201	L16 - L17
19	Percentage transportation allocation to O&M		73.4%	
20	Staff recommended pro forma adjustment to Fleet Fuel Expense	$	61,069	

C Average cost of fuel for November 2006 through January 2007 reflects UNS Gas' actual average fuel cost for that period per Duke's rebuttal testimony

UNS Gas, Inc.
Postage Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-16

Revised

Line No.	Description	Amount		Reference
1	UNS Gas Annualized Postage Expense	$ 529,380		A
2	Staff Annualized Postage Expense	$ 503,356		B
3	Adjustment to Postage Expense	$ (26,024)	a	L2 - L1

Notes and Source

A: UNS Gas workpaper used in calculating its Postage Expense adjustment

B: **Staff recommended Postage Expense Annualization**

Test Year Postage Expense	$ 445,171	
Postage increases effective 1/8/06 and 5/14/07 ($.04/$.37)	1.11	
Increased Postage Expense	493,298	
Ratio of Weighted Average Annualized Customers	1.02039	b
Annualized Postage Expense per Staff	$ 503,356	

a: Allocation of Staff adjustment to FERC accounts

FERC 903	$ (24,749)	95.1%
FERC 921	$ (1,275)	4.9%
	$ (26,024)	100.0%

b: TY average and year end customers derived from the following rate classes per UNS Gas response to STF 11.10:

	Average	Dec. 2005
Residential - 10	118,821	121,125
Residential CARES -12	5,264	5,556
Small Volume Commercial - 20	10,849	11,017
Large Volume Commercial -22	10	11
Small Volume Public Authority - 40	1,042	1,051
Large Volume Public Authority - 42	6	5
	135,992	138,765

Additional Postage Expense through Customer Annualization 1.02039

UNS Gas, Inc.
Interest Synchronization

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-17
Page 1 of 1
Revised

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	154,547,272	Schedule B
2	Weighted cost of debt		3.65%	Schedule D
3	Synchronized interest deduction	$	5,640,975	Line 1 x Line 2
4	Synchronized interest deduction per UNS Gas	$	5,334,825	Note A
5	Difference (decreased) increased interest deduction	$	306,150	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	STF 5.76, item 6
7	Increase (decrease) to income tax expense	$	(118,168)	

Notes and Source

A RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Also, UNS Gas filing, Schedule B-5, page 3 of 3, line 18

UNS Gas, Inc.
Corporate Cost Allocations

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-18
Page 1 of 1
Added

Line No.	Description	Amount	Reference
1	Adjustment to Corporate Cost Allocations	$ (12,765)	A

A: Adjustment proposed by RUCO and agreed to by UNS Gas Inc. per rebuttal testimony of Company witness Dallas Dukes

UNS Gas, Inc.
Rate Case Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-19

Added

Line No.	Description	Amount	Reference
1	UNS Gas Rate Case Expense per Company Filing	$ 200,000	A
2	Staff Recommended Rate Case Expense	$ 85,000	B
3	Adjustment to Rate Case Expense	$ (115,000)	L2 - L1

Notes and Source
A: UNS Gas filing, Schedule C-2, page 2, line 5

B:	Staff Recommended Rate Case Expense	$ 255,000
	Normalized Over Three Years	3
	Staff Recommended Normalized Rate Case Expense	$ 85,000

UNS Gas, Inc.
CARES Related Amortization

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-20
Page 1 of 1
Added

Line No.	Description	Amount	Reference
1	Adjustment to CARES Related Amortization	$ (441,511)	A

Notes and Source

A: *Surrebuttal testimony of Staff witness Julie McNeely-Kirwan*

Attachment RCS-S1(R)
To the Surrebuttal Testimony
Of Staff Witness Ralph C. Smith

Staff Proposed Rate Design Summary
And Proof of Revenue
(Revised)

Attachment RCS-S1R

Staff Revised Rate Design Schedules

Accompanying the Surrebuttal Testimony of Ralph C. Smith

Schedule	Description	Pages
RD-1	Staff Proof of Revenue at Present and Proposed Rates	2
RD-2	Calculation of CARES (Rate R12) Total Discount for the Winter Months	1
RD-3	Calculation of An Across the Board Increase	1
RD-4	Analysis of Revenues Generated by Fixed Charges	1
RD-5	Calculation of Distribution Rate	1
	Total Pages	6

PROOF OF REVENUE USING THE COMPANY'S BILLING UNITS
STATED ON SCHEDULE H-2, PAGE 1 OF 2

Line No.	Class of Service	Adjusted Billed BD (from H-2, page 1)	Existing Rates	Current Revenues	Adjusted Booked Revenue	Difference	Staff Billing Unit Adjustments: Staff Adj. for Customer Annualizaton	Staff Billing Unit Adjustments: Staff Adj. for Weather Normalization	Adjusted Billing units	Current Revenues	Staff Adjusted Average No. of Customers
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Residential Service (R10)										
1	Customer Charge	1,447,632	$ 7.00	$10,133,424			5,883		1,453,515	10,174,605	121,126
2	Distribution Margin Therms	68,951,676	$0.3004	$20,713,083			129,654	4,916	69,086,246	20,753,508	
3	TOTAL R10			$30,846,507	$31,176,937	($330,430)				30,928,113	
	Residential Service Cares (R12)										
4	Customer Charge	67,920	$ 7.00	$475,440			(1,252)		66,668	466,676	5,556
5	Distribution Margin Therms	2,813,844	$0.3004	$845,279			(40,412)	(872)	2,772,560	832,877	
6	TOTAL R12			$1,320,719	$975,486	$345,233				1,299,553	
	Small Volume Commercial Service (C20)										
7	Customer Charge	131,028	$ 11.00	$1,441,308			1,178		132,206	1,454,266	11,017
8	Distribution Margin Therms	29,014,067	$0.2420	$7,021,404			139,670	3,550	29,157,287	7,056,063	
9	TOTAL R20			$8,462,712	$8,531,880	($69,168)				8,510,329	
	Large Volume Commercial Service (C22) and Commercial Transportatjion										
10	Customer Charge	204	$ 85.00	$17,340			4		208	17,680	17
11	Distribution Margin Therms	3,756,735	$0.1551	$582,670			32,215		3,788,950	587,666	
12	TOTAL R22			$600,010	$661,907	($61,897)				605,346	
	Small Volume Industrial Service (I-30)										
13	Customer Charge	156	$ 11.00	$1,716					156	1,716	13
14	Distribution Margin Therms	511,826	$0.2122	$108,609					511,826	108,609	
15	TOTAL I30			$110,325	$109,190	$1,136				110,325	
	Large Volume Industrial Service (I-32)										
16	Customer Charge	228	$ 85.00	$19,380					228	19,380	19
17	Distribution Margin Therms	21,610,146	$0.0864	$1,867,117					21,610,146	1,867,117	
18	TOTAL I32			$1,886,497	$1,971,743	($85,246)				1,886,497	
	Small Volume Public Authority (PA-40)										
19	Customer Charge	12,696	$ 11.00	$139,656			(32)		12,664	139,304	1,055
20	Distribution Margin Therms	5,828,186	$0.2354	$1,371,955			(19,344)	(476)	5,808,366	1,367,289	
21	TOTAL PA40			$1,511,611	$1,527,532	($15,921)				1,506,593	
	Large Volume Public Authority (PA-42)										
22	Customer Charge	108	$ 85.00	$9,180			(4)		104	8,840	9
23	Distribution Margin Therms	5,558,725	$0.1084	$602,566			(33,636)		5,525,089	598,920	
24	TOTAL PA42			$611,746	$637,909	($26,163)				607,760	
	Special Gas Light Service (PA-44)										
25	Customer Charge Lighting Group A	864	$ 13.57	$11,724					864	11,724	
26	Customer Charge Lighting Group B	3,756	$ 16.28	$61,148					3,756	61,148	
27	TOTAL PA44	101,855		$72,872	$73,078	($206)				72,872	
	Irrigation Service (IR-60)										
28	Customer Charge	72	$ 11.00	$792					72	792	6
29	Distribution Margin Therms	86,603	$0.2876	$24,965					86,603	24,965	
30	TOTAL IR60			$25,757	$23,562	$2,194				25,757	
31	Total Gas Service Revenue at Present Rates			$45,448,756	$45,689,224	($240,468)				45,553,146	
32	Staff Adjusted Revenue at Rresent Rates			Note A	Note A	Note A				45,793,618	
33	Difference								Difference	(240,472)	
										Note A	
34	Total Bills	1,660,047							1,665,824		
35	Total Monthly Customers	138,340 [B]							138,822 [B]		138,821 [B]
36	Total Distribution Therms	138,233,863							138,347,273		

Notes and Source
Col.A: UNS Gas filing, Schedule H-2, page 1 of 2, adjusted average number of customers (x 12) and adjusted therm sales
UNS Gas filing, Schedule H-2, page 1 of 2, adjusted average number of customers lists 3 customers for PA44; billing units for PA44 on lines 25&26 are from a workpaper
Col.B: UNS Gas filing, Schedule H-3, Present Rates
Col.C: Col.A x Col.B
Col.D: UNS Gas filing, Schedule H-2, page 2 of 2, Adjusted Net Revenues column
Total agrees with UNS Gas filing, Schedule H-1, Adjusted Present Net Revenue subtotal on line 8 of that schedule.
Col.E: Col.C - Col.D
Col.F: Staff workpapers
Col.G: Staff workpapers
Col.H: Col.A + Col.F + Col.G
Col.I: Col.H x Col.B
[A] The billing units from the Company's Schedule H-2, page 1 of 2 produce a net revenue of $45,488,756 which is 240,468 less than what the Company states in Schedule H-2, page 2 of 2.
[B] Includes 3 customers for PA44

Line	Class of Service	Adjusted Billing Units A	Existing Rates (B)	Current Revenues (C)	Staff Proposed New Rates (D)	Proposed Revenues (E)	Residential Cares (R-12) Winter Discount (F)
	Residential Service (R10)						
1	Customer Charge	1,453,515	7.00	$ 10,174,605	8.50	$ 12,354,878	
2	Distribution Margin Therms	69,086,246	0.3004	$ 20,753,508	0.3177	$ 21,945,351	
3	TOTAL R10			$ 30,928,113		$ 34,300,229	
	Residential Service Cares (R12)						
4	Customer Charge	66,668	7.00	$ 466,676	7.00	$ 466,676	
5	Distribution Margin Therms	2,772,560	0.3004	$ 832,877	0.3177	$ 880,707	$ (320,006)
6	TOTAL R12			$ 1,299,553		$ 1,347,383	
	Small Volume Commercial Service (C20)						
7	Customer Charge	132,206	11.00	$ 1,454,266	13.50	$ 1,784,781	
8	Distribution Margin Therms	29,157,287	0.2420	$ 7,056,063	0.2625	$ 7,653,436	
9	TOTAL C20			$ 8,510,329		$ 9,438,217	
	Large Volume Commercial Service (C22) and Commercial Transportation						
10	Customer Charge	208	85.00	$ 17,680	100.00	$ 20,800	
11	Distribution Margin Therms	3,788,950	0.1551	$ 587,666	0.1717	$ 650,547	
12	TOTAL C22			$ 605,346		$ 671,347	
	Small Volume Industrial Service (I-30)						
13	*Customer Charge*	156	11.00	$ 1,716	13.50	$ 2,106	
14	Distribution Margin Therms	511,826	0.2122	$ 108,609	0.2349	$ 120,248	
15	TOTAL I30			$ 110,325		$ 122,354	
	Large Volume Industrial Service (I-32) and Industrial Transportation						
16	Customer Charge	228	85.00	$ 19,380	100.00	$ 22,800	
17	Distribution Margin Therms	21,610,146	0.0864	$ 1,867,117	0.0958	$ 2,069,383	
18	TOTAL I32			$ 1,886,497		$ 2,092,183	
	Small Volume Public Authority (PA-40)						
19	Customer Charge	12,664	11.00	$ 139,304	13.50	$ 170,964	
20	Distribution Margin Therms	5,808,366	0.2354	$ 1,367,289	0.2582	$ 1,499,894	
21	TOTAL PA40			$ 1,506,593		$ 1,670,858	
	Large Volume Public Authority (PA-42) and Public Authority Transportation						
22	Customer Charge	104	85.00	$ 8,840	100.00	$ 10,400	
23	Distribution Margin Therms	5,525,089	0.1084	$ 598,920	0.1201	$ 663,624	
24	TOTAL PA42			$ 607,760		$ 674,024	
	Special Gas Light Service (PA-44)						
25	Customer Charge Lighting Group A	864	13.57	$ 11,724	15.05	$ 13,003	
26	Customer Charge Lighting Group B	3,756	16.28	$ 61,148	18.06	$ 67,815	
27	TOTAL PA44			$ 72,872		$ 80,817	
	Irrigation Service (IR-60)						
28	Customer Charge	72	11.00	$ 792	13.50	$ 972	
29	Distribution Margin Therms	86,803	0.2876	$ 24,965	0.3179	$ 27,593	
30	TOTAL IR60			$ 25,757		$ 28,565	
						Increase	
30	**Total Revenue Requirements**			**$ 45,553,146**		$ 4,552,826	**$ 50,105,972**
31	**Staff revenues**			$ 45,793,618		$ 4,312,354	$ 50,105,972
33	*Difference*			*$ (240,472)*		*$ 240,472*	
				Note A			

Notes

[A] The (240,472) billing unit-related difference is incorporated into the development of Staff's Proposed Rates
Staff's proposed rates are designed to recover the adjusted revenue requirement using the adjusted billing determinants in column A.

Calculation of CARES (Rate R12) Total Discount for the Winter Months
Discount equals 15 cents off of the per therm rate, up to 100 therms

Provided from STF 15.3

Line	Month	Average monthly therms	Discount	Annualized Customers	R12 Therm-Based Revenue Discount
		(A)	(B)	(C)	(D)
1	Nov	29	0.1500	5,556	$ 24,167
2	Dec	66	0.1500	5,556	$ 55,001
3	Jan	92	0.1500	5,556	$ 76,668
4	Feb	76	0.1500	5,556	$ 63,335
5	March	66	0.1500	5,556	$ 55,001
6	April	55	0.1500	5,556	$ 45,834
7					$ 320,006
8	Average Monthly therms	64			
9	Discount for first 100 therms	0.1500			
10	Average Monthly Savings per customer	9.60			
11	For Six Months	57.60			
12	Annual # of customers	66,668	Schedule RD-1, pages 1 and 2		
13	Monthly customers	5,556	Schedule RD-1, page 2		
14	Total Discount	$ 320,006			

UNS Gas Inc. Rate Case; Docket No. G-04204A-06-0463
Calculation of An Across the Board Increase

Line	Class	Current Net Revenue (A)	Staff Proposed Increase (B)	Difference in Billing units vs Adj. Revenue (C)	Adjusted Proposed Increase (D)	Proposed Net Revenue (E)	Across-The Board Increase (F)
1	Total	45,553,146	**4,312,354**	240,472	**4,552,826**	50,105,972	
2	Residential CARES (R12)	1,299,553			47,830		
3	Total without CARES	44,253,593			4,504,996		10.18%
4	Allocation of CARES (R12) Discount				320,006		0.72%
5	**Across the Board %**						**10.90%** (A)
6	Residential (R10)	30,928,113			3,372,115	34,300,229	10.90%
7	Residential Cares (R12)	1,299,553			47,830	1,347,383	3.68% (B)
8	Small Comm Serv (C-20)	8,510,329			927,888	9,438,217	10.90%
9	Large Comm Serv (C-22) and Comm Trans	605,346			66,001	671,347	10.90%
10	Sm. Industrial (I-30)	110,325			12,029	122,354	10.90%
11	Large Industrial (I-32) and Industial Trans	1,886,497			205,686	2,092,183	10.90%
12	Sm. Public Authority (PA-40)	1,506,593			164,265	1,670,858	10.90%
13	Lg. Public Authority (PA-42) and PA Trans	607,760			66,264	674,024	10.90%
14	Special Gas Light (PA-44)	72,872			7,945	80,817	10.90%
15	Irrigation (I-60)	25,757			2,808	28,565	10.90%
16	TOTAL	45,553,146			4,872,832	50,425,978	
17	CARES winter therm discount				$ 320,006	$ 320,006	
18	Total Revenue Increase				4,552,826	50,105,972	

Notes and Source

Net Revenue is the adjusted Net Revenue proposed by Staff
(A) Across the board for all classes except Cares class; *including discount*
(B) To ensure therm rate is same as Residential
See Schedule RD-2 for development of the CARES discount

Line	Description	Totals	Residential R10	Residential Cares R12	Small Comm Serv C20	Large Comm Serv & Comm Trans C22	Sm. Industrial I30	Large Industrial & Industrial Trans I32	Sm. Public Authority PA-40	Lg. Public Authority and Public Authority Trans PA-42	Special Gas Light PA-44 Group A	Special Gas Light PA-44 Group B	Irrigation IR-60
1	**# of Customers**		1,453,515	66,668	132,206	208	156	228	12,664	104	864	3,756	72
	CUSTOMER CHARGE												
	CURRENT												
2	Customer Charge		$ 7.00	$ 7.00	$ 11.00	$ 85.00	$ 11.00	$ 85.00	$ 11.00	$ 85.00	$ 13.57	$ 16.28	$ 11.00
	PROPOSED												
3	Customer Charge		$ 8.50	$ 7.00	$ 13.50	$ 100.00	$ 13.50	$ 100.00	$ 13.50	$ 100.00	$ 15.05	$ 18.06	$ 13.50
	% of Increase												
4	Customer Charge		21.43%	0.00%	22.73%	17.65%	22.73%	17.65%	22.73%	17.65%	10.90%	10.90%	22.73%
	REVENUES GENERATED BY CUSTOMER CHARGE												
5	Current Revenues from Customer Charge	$ 12,356,131	$ 10,174,605	$ 466,676	$ 1,454,266	$ 17,680	$ 1,716	$ 19,360	$ 139,304	$ 8,840	$ 11,724	$ 61,148	$ 792
6	Total Revenues	$ 45,553,146	$ 30,928,113	$ 1,299,553	$ 8,510,329	$ 605,346	$ 110,325	$ 1,886,497	$ 1,506,593	$ 607,760	$ 11,724	$ 61,148	$ 25,757
7	% of fixed charges	27%	33%	36%	17%	3%	2%	1%	9%	1%	100%	100%	3%
	PROPOSED CUSTOMER CHARGE												
8	Proposed Increase	$ 4,552,826	3,372,115	47,830	927,888	66,001	12,029	205,686	164,265	66,264	$ 1,278	$ 6,667	2,808
9	**Total Revenues (includes discount)**	$ 50,105,972	34,300,229	1,347,383	9,438,217	671,347	122,354	2,092,183	1,670,858	674,024	13,003	67,815	28,565
10	Proposed Revenues from Customer Charge	$ 14,915,194	$ 12,354,878	$ 466,676	$ 1,784,781	$ 20,800	$ 2,106	$ 22,800	$ 170,964	$ 10,400	$ 13,003	$ 67,815	$ 972
11	*% of Fixed Charges*	30%	36%	35%	19%	3%	2%	1%	10%	2%	100%	100%	3%
12	Increase in Revenues from Customer Charge	$ 2,559,063	$ 2,180,273	$ -	$ 330,515	$ 3,120	$ 390	$ 3,420	$ 31,660	$ 1,560	$ 1,278	$ 6,667	$ 180
13	Customer Charge Increases as Percent of Total Revenue Increases	56%	65%	0%	36%	5%	3%	2%	19%	2%	100%	100%	6%

Footnotes:
PA-44 Group A and B increase is based on their % of present revenue collected compared to the total

UNS Gas Inc. Rate Case; Docket No. G-04204A-06-0463
Calculation of Distribution Rate

Attachment RCS-S1R
Schedule RD-5

Line	Class	Revenue Increase (A)	Current Revenues (B)	Proposed Revenues (C)	Proposed Cust. Charge Rev. (D)	Difference (E)	Distribution Therms (F)	Distribution Rate (G)
1	Total	$ 4,552,826	$ 45,553,146	$ 50,105,972			138,347,273	
2	Residential (R-10)	3,372,115	$ 30,928,113	$ 34,300,229	$ 12,354,878	$ 21,945,351	69,086,246	$ 0.3177
3	Residential Cares (R-12) (Note A)	47,830	$ 1,299,553	$ 1,347,383	$ 466,676	$ 880,707	2,772,560	$ 0.3177
4	Small Comm Serv (C-20)	927,888	$ 8,510,329	$ 9,438,217	$ 1,784,781	$ 7,653,436	29,157,287	$ 0.2625
5	Large Comm Serv (C-22) and Comm Trans	66,001	$ 605,346	$ 671,347	$ 20,800	$ 650,547	3,788,950	$ 0.1717
6	Sm. Industrial (I-30)	12,029	$ 110,325	$ 122,354	$ 2,106	$ 120,248	511,826	$ 0.2349
7	Large Industrial (I-32) and Trans	205,686	$ 1,886,497	$ 2,092,183	$ 22,800	$ 2,069,383	21,610,146	$ 0.0958
8	Sm. Public Authority (PA-40)	164,265	$ 1,506,593	$ 1,670,858	$ 170,964	$ 1,499,894	5,808,366	$ 0.2582
9	Lg. Public Authority (PA-42) and Trans	66,264	$ 607,760	$ 674,024	$ 10,400	$ 663,624	5,525,089	$ 0.1201
10	Special Gas Light (PA-44) (Note B)	7,945	$ 72,872	$ 80,817	$ 80,817			
11	Irrigation (I-60)	2,808	$ 25,757	$ 28,565	$ 972	$ 27,593	86,803	$ 0.3179
12	TOTALS	$ 4,872,832	$ 45,553,146	$ 50,425,978	$ 14,915,194	$ 35,510,784	138,347,273	
13	CARES winter discount	$ (320,006)		$ (320,006)				
14	TOTALS after reflecting CARES discount	$ 4,552,826	$ 45,553,146	$ 50,105,972				

Notes

Line	Note A: Calculation of Discount for Residential Cares (R12)	$ 57.60
15	Total Annual Customers	66,668
16	Total Monthly Customers	5,556
17	Total Discount for Six months	$ 320,006

Note B: Rate PA-44 has Customer Charges Only
Col.D, Customer Charge Revenue amounts are from Schedule RD-1, page 2, Col.E; amounts on Schedule RD-4, line 10, may differ slightly for some rate classes due to rounding.

Attachment RCS-S2(R)
To the Surrebuttal Testimony
Of Staff Witness Ralph C. Smith

Bill Impact Analysis
Of Staff Proposed Rate Design
(Revised)

Note: When discussing rate design and representing impacts of various rate design characteristics, for the total bill impact comparisons, I have included the current base cost of gas and the current (February 2007) PGA rate. Both UNS Gas and Staff in the current proceeding are recommending that all gas costs be removed from base rates and addressed in the PGA prospectively. The total bill impact comparisons presented here are exclusive of the Staff's recommended revised DSM rate of $0.0025 per therm.

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Residential Service (R10)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge (Sum: Apr-Nov)	$7.00	$8.50	A & C
2	Distribution Margin Therms	$ 0.3004	$ 0.3177	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	5	$7.00	$ 1.50	$8.50	$ 3.92	$12.42	$8.50	$ 1.59	$10.09	$ 3.92	$14.01	$1.59	12.80%	$1.59	18.71%
7	10	$7.00	$ 3.00	$10.00	$ 7.84	$17.84	$8.50	$ 3.18	$11.68	$ 7.84	$19.52	$1.68	9.42%	$1.68	16.80%
8	20	$7.00	$ 6.01	$13.01	$ 15.69	$28.70	$8.50	$ 6.35	$14.85	$ 15.69	$30.54	$1.84	6.41%	$1.84	14.14%
9	35	$7.00	$ 10.51	$17.51	$ 27.45	$44.96	$8.50	$ 11.12	$19.62	$ 27.45	$47.07	$2.11	4.69%	$2.11	12.05%
10	50	$7.00	$ 15.02	$22.02	$ 39.22	$61.24	$8.50	$ 15.88	$24.38	$ 39.22	$63.60	$2.36	3.85%	$2.36	10.72%
11	75	$7.00	$ 22.53	$29.53	$ 58.83	$88.36	$8.50	$ 23.82	$32.32	$ 58.83	$91.15	$2.79	3.16%	$2.79	9.45%
12	100	$7.00	$ 30.04	$37.04	$ 78.44	$115.48	$8.50	$ 31.77	$40.27	$ 78.44	$118.71	$3.23	2.80%	$3.23	8.72%
13	250	$7.00	$ 75.10	$82.10	$ 196.10	$278.20	$8.50	$ 79.41	$87.91	$ 196.10	$284.01	$5.81	2.09%	$5.81	7.08%
14	500	$7.00	$ 150.20	$157.20	$ 392.20	$549.40	$8.50	$ 158.83	$167.33	$ 392.20	$559.53	$10.13	1.84%	$10.13	6.44%

	Rate Component	Present Rates	Staff Proposed	Notes
15	Customer Charge (Winter: Dec-Mar)	$7.00	$8.50	A & C
16	Distribution Margin Therms	$ 0.3004	$ 0.3177	A
17	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
18	Base gas cost	$ 0.4000	$ 0.4000	B
19	Gas Cost Subtotal	$ 0.7844	$ 0.7844	

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
20	5	$7.00	$ 1.50	$8.50	$ 3.92	$12.42	$8.50	$ 1.59	$10.09	$ 3.92	$14.01	$1.59	12.80%	$1.59	18.71%
21	10	$7.00	$ 3.00	$10.00	$ 7.84	$17.84	$8.50	$ 3.18	$11.68	$ 7.84	$19.52	$1.68	9.42%	$1.68	16.80%
22	20	$7.00	$ 6.01	$13.01	$ 15.69	$28.70	$8.50	$ 6.35	$14.85	$ 15.69	$30.54	$1.84	6.41%	$1.84	14.14%
23	35	$7.00	$ 10.51	$17.51	$ 27.45	$44.96	$8.50	$ 11.12	$19.62	$ 27.45	$47.07	$2.11	4.69%	$2.11	12.05%
24	50	$7.00	$ 15.02	$22.02	$ 39.22	$61.24	$8.50	$ 15.88	$24.38	$ 39.22	$63.60	$2.36	3.85%	$2.36	10.72%
25	75	$7.00	$ 22.53	$29.53	$ 58.83	$88.36	$8.50	$ 23.82	$32.32	$ 58.83	$91.15	$2.79	3.16%	$2.79	9.45%
26	100	$7.00	$ 30.04	$37.04	$ 78.44	$115.48	$8.50	$ 31.77	$40.27	$ 78.44	$118.71	$3.23	2.80%	$3.23	8.72%
27	250	$7.00	$ 75.10	$82.10	$ 196.10	$278.20	$8.50	$ 79.41	$87.91	$ 196.10	$284.01	$5.81	2.09%	$5.81	7.08%
28	500	$7.00	$ 150.20	$157.20	$ 392.20	$549.40	$8.50	$ 158.83	$167.33	$ 392.20	$559.53	$10.13	1.84%	$10.13	6.44%
	Typical Jan Usage														
29	87	$7.00	$ 26.13	$33.13	$ 68.24	$101.37	$8.50	$ 27.64	$36.14	$ 68.24	$104.38	$3.01	2.97%	$3.01	9.09%

Notes

A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1

B Cost of Gas Inputs workpaper

C UNS Gas is proposing a different customer charge rate of $20 and $11 per month for summer and winter, respectively. Staff recommends the same customer charge rate for all months.

R10

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Residential Service CARES (R12)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge (Sum: May-Oct)	$7.00	$7.00	A
2	Distribution Margin Therms	$ 0.3004	$ 0.3177	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

	Average Therms Per Month	Present Rates Customer Charge	Present Rates Distribution Margin	Present Rates Base Rates	Present Rates Gas Cost	Present Rates Total Bill	Proposed Rates Customer Charge	Proposed Rates Distribution Margin	Proposed Rates Base Rates	Proposed Rates Gas Cost	Proposed Rates Total Bill	Total Bill Proposed Increase $	Total Bill Proposed Increase %	Base Rates Only Proposed Increase $	Base Rates Only Proposed Increase %
6	5	$7.00	$ 1.50	$8.50	$ 3.92	$12.42	$7.00	$ 1.59	$8.59	$ 3.92	$12.51	$0.09	0.72%	$0.09	1.06%
7	10	$7.00	$ 3.00	$10.00	$ 7.84	$17.84	$7.00	$ 3.18	$10.18	$ 7.84	$18.02	$0.18	1.01%	$0.18	1.80%
8	20	$7.00	$ 6.01	$13.01	$ 15.69	$28.70	$7.00	$ 6.35	$13.35	$ 15.69	$29.04	$0.34	1.18%	$0.34	2.61%
9	35	$7.00	$ 10.51	$17.51	$ 27.45	$44.96	$7.00	$ 11.12	$18.12	$ 27.45	$45.57	$0.61	1.36%	$0.61	3.48%
10	50	$7.00	$ 15.02	$22.02	$ 39.22	$61.24	$7.00	$ 15.88	$22.88	$ 39.22	$62.10	$0.86	1.40%	$0.86	3.91%
11	75	$7.00	$ 22.53	$29.53	$ 58.83	$88.36	$7.00	$ 23.82	$30.82	$ 58.83	$89.65	$1.29	1.46%	$1.29	4.37%
12	100	$7.00	$ 30.04	$37.04	$ 78.44	$115.48	$7.00	$ 31.77	$38.77	$ 78.44	$117.21	$1.73	1.50%	$1.73	4.67%
13	250	$7.00	$ 75.10	$82.10	$ 196.10	$278.20	$7.00	$ 79.41	$86.41	$ 196.10	$282.51	$4.31	1.55%	$4.31	5.25%
14	500	$7.00	$ 150.20	$157.20	$ 392.20	$549.40	$7.00	$ 158.83	$165.83	$ 392.20	$558.03	$8.63	1.57%	$8.63	5.49%

	Rate Component	Present Rates	Staff Proposed	Notes
15	Customer Charge (Winter)	$7.00	$7.00	A & C
16	Distribution Margin Therms	$ 0.3004	$ 0.3177	A
16a	Margin Rate Discount (Nov-Apr <100 therms)	$ 0.1500	$ 0.1500	C
17	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
18	Base gas cost	$ 0.4000	$ 0.4000	B
19	Gas Cost Subtotal	$ 0.7844	$ 0.7844	

	Average Therms Per Month	Present Rates Customer Charge	Present Rates Distribution Margin	Present Rates Base Rates	Present Rates Gas Cost	Present Rates Total Bill	Proposed Rates Customer Charge	Proposed Rates Distribution Margin	Proposed Rates Base Rates	Proposed Rates Gas Cost	Proposed Rates Total Bill	Total Bill Proposed Increase $	Total Bill Proposed Increase %	Base Rates Only Proposed Increase $	Base Rates Only Proposed Increase %
20	5	$7.00	$ 0.75	$7.75	$ 3.92	$11.67	$7.00	$ 0.84	$7.84	$ 3.92	$11.76	$0.09	0.77%	$0.09	1.16%
21	10	$7.00	$ 1.50	$8.50	$ 7.84	$16.34	$7.00	$ 1.68	$8.68	$ 7.84	$16.52	$0.18	1.10%	$0.18	2.12%
22	20	$7.00	$ 3.01	$10.01	$ 15.69	$25.70	$7.00	$ 3.35	$10.35	$ 15.69	$26.04	$0.34	1.32%	$0.34	3.40%
23	35	$7.00	$ 5.26	$12.26	$ 27.45	$39.71	$7.00	$ 5.87	$12.87	$ 27.45	$40.32	$0.61	1.54%	$0.61	4.98%
24	50	$7.00	$ 7.52	$14.52	$ 39.22	$53.74	$7.00	$ 8.38	$15.38	$ 39.22	$54.60	$0.86	1.60%	$0.86	5.92%
25	75	$7.00	$ 11.28	$18.28	$ 58.83	$77.11	$7.00	$ 12.57	$19.57	$ 58.83	$78.40	$1.29	1.67%	$1.29	7.06%
26	100	$7.00	$ 15.04	$22.04	$ 78.44	$100.48	$7.00	$ 16.77	$23.77	$ 78.44	$102.21	$1.73	1.72%	$1.73	7.85%
27	250	$7.00	$ 60.10	$67.10	$ 196.10	$263.20	$7.00	$ 64.42	$71.42	$ 196.10	$267.52	$4.32	1.64%	$4.32	6.44%
28	500	$7.00	$ 135.20	$142.20	$ 392.20	$534.40	$7.00	$ 143.83	$150.83	$ 392.20	$543.03	$8.63	1.61%	$8.63	6.07%
	Average														
29	64	$7.00	$ 9.63	$16.63	$ 50.20	$66.83	$7.00	$ 10.73	$17.73	$ 50.20	$67.93	$1.10	1.65%	$1.10	6.61%

Notes
A Staff Proof of Revenue. See *Attachment RCS-S1, Schedule RD-1*
B Cost of Gas Inputs workpaper
C Direct testimony of Staff witness Julie McNeely-Kirwan

Line 27, Distribution Margin

Therms	Present Rate	Present Amount	Proposed Rate	Proposed Amount
100	$ 0.1504	$ 15.04	$ 0.1677	$ 16.77
150	$ 0.3004	$ 45.06	$ 0.3177	$ 47.65
		$ 60.10		$ 64.42

Line 28, Distribution Margin

Therms	Present Rate	Present Amount	Proposed Rate	Proposed Amount
100	$ 0.1504	$ 15.04	$ 0.1677	$ 16.77
400	$ 0.3004	$ 120.16	$ 0.3177	$ 127.06
		$ 135.20		$ 143.83

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Small Commercial Service (C20)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2420	$ 0.2625	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 12.10	$23.10	$ 39.22	$62.32	$13.50	$ 13.12	$26.62	$ 39.22	$65.84	$3.52	5.65%	$3.52	15.24%
7	100	$11.00	$ 24.20	$35.20	$ 78.44	$113.64	$13.50	$ 26.25	$39.75	$ 78.44	$118.19	$4.55	4.00%	$4.55	12.93%
8	500	$11.00	$ 121.00	$132.00	$ 392.20	$524.20	$13.50	$ 131.24	$144.74	$ 392.20	$536.94	$12.74	2.43%	$12.74	9.65%
9	1,000	$11.00	$ 242.00	$253.00	$ 784.40	$1,037.40	$13.50	$ 262.49	$275.99	$ 784.40	$1,060.39	$22.99	2.22%	$22.99	9.09%
10	1,500	$11.00	$ 363.00	$374.00	$ 1,176.60	$1,550.60	$13.50	$ 393.73	$407.23	$ 1,176.60	$1,583.83	$33.23	2.14%	$33.23	8.89%
11	2,500	$11.00	$ 605.00	$616.00	$ 1,961.00	$2,577.00	$13.50	$ 656.22	$669.72	$ 1,961.00	$2,630.72	$53.72	2.08%	$53.72	8.72%
12	5,000	$11.00	$1,210.00	$1,221.00	$ 3,922.00	$5,143.00	$13.50	$ 1,312.44	$1,325.94	$ 3,922.00	$5,247.94	$104.94	2.04%	$104.94	8.59%
13	7,500	$11.00	$1,815.00	$1,826.00	$ 5,883.00	$7,709.00	$13.50	$ 1,968.66	$1,982.16	$ 5,883.00	$7,865.16	$156.16	2.03%	$156.16	8.55%
14	10,000	$11.00	$2,420.00	$2,431.00	$ 7,844.00	$10,275.00	$13.50	$ 2,624.88	$2,638.38	$ 7,844.00	$10,482.38	$207.38	2.02%	$207.38	8.53%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Large Commercial Service (C22)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$85.00	$100.00	A
2	Distribution Margin Therms	$ 0.1551	$ 0.1717	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

Line	Average Therms Per Month	Present Rates: Customer Charge	Present Rates: Distribution Margin	Present Rates: Base Rates	Present Rates: Gas Cost	Present Rates: Total Bill	Proposed Rates: Customer Charge	Proposed Rates: Distribution Margin	Proposed Rates: Base Rates	Proposed Rates: Gas Cost	Proposed Rates: Total Bill	Total Bill: Proposed Increase $	Total Bill: Proposed Increase %	Base Rates Only: Proposed Increase $	Base Rates Only: Proposed Increase %
6	10,001	$85.00	$ 1,551.16	$1,636.16	$ 7,844.78	$9,480.94	$100.00	$ 1,717.13	$1,817.13	$ 7,844.78	$9,661.91	$180.97	1.91%	$180.97	11.06%
7	12,500	$85.00	$ 1,938.75	$2,023.75	$ 9,805.00	$11,828.75	$100.00	$ 2,146.20	$2,246.20	$ 9,805.00	$12,051.20	$222.45	1.88%	$222.45	10.99%
8	15,000	$85.00	$ 2,326.50	$2,411.50	$ 11,766.00	$14,177.50	$100.00	$ 2,575.44	$2,675.44	$ 11,766.00	$14,441.44	$263.94	1.86%	$263.94	10.95%
9	17,500	$85.00	$ 2,714.25	$2,799.25	$ 13,727.00	$16,526.25	$100.00	$ 3,004.68	$3,104.68	$ 13,727.00	$16,831.68	$305.43	1.85%	$305.43	10.91%
10	20,000	$85.00	$ 3,102.00	$3,187.00	$ 15,688.00	$18,875.00	$100.00	$ 3,433.92	$3,533.92	$ 15,688.00	$19,221.92	$346.92	1.84%	$346.92	10.89%
11	25,000	$85.00	$ 3,877.50	$3,962.50	$ 19,610.00	$23,572.50	$100.00	$ 4,292.40	$4,392.40	$ 19,610.00	$24,002.40	$429.90	1.82%	$429.90	10.85%
12	30,000	$85.00	$ 4,653.00	$4,738.00	$ 23,532.00	$28,270.00	$100.00	$ 5,150.88	$5,250.88	$ 23,532.00	$28,782.88	$512.88	1.81%	$512.88	10.82%
13	45,000	$85.00	$ 6,979.50	$7,064.50	$ 35,298.00	$42,362.50	$100.00	$ 7,726.32	$7,826.32	$ 35,298.00	$43,124.32	$761.82	1.80%	$761.82	10.78%
14	75,000	$85.00	$ 11,632.50	$11,717.50	$ 58,830.00	$70,547.50	$100.00	$ 12,877.20	$12,977.20	$ 58,830.00	$71,807.20	$1,259.70	1.79%	$1,259.70	10.75%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Small Volume Industrial Service (I-30)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2122	$ 0.2349	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 10.61	$21.61	$ 39.22	$60.83	$13.50	$ 11.75	$25.25	$ 39.22	$64.47	$3.64	5.98%	$3.64	16.84%
7	100	$11.00	$ 21.22	$32.22	$ 78.44	$110.66	$13.50	$ 23.49	$36.99	$ 78.44	$115.43	$4.77	4.31%	$4.77	14.80%
8	500	$11.00	$ 106.10	$117.10	$ 392.20	$509.30	$13.50	$ 117.47	$130.97	$ 392.20	$523.17	$13.87	2.72%	$13.87	11.84%
9	1,000	$11.00	$ 212.20	$223.20	$ 784.40	$1,007.60	$13.50	$ 234.94	$248.44	$ 784.40	$1,032.84	$25.24	2.50%	$25.24	11.31%
10	1,500	$11.00	$ 318.30	$329.30	$ 1,176.60	$1,505.90	$13.50	$ 352.41	$365.91	$ 1,176.60	$1,542.51	$36.61	2.43%	$36.61	11.12%
11	2,500	$11.00	$ 530.50	$541.50	$ 1,961.00	$2,502.50	$13.50	$ 587.35	$600.85	$ 1,961.00	$2,561.85	$59.35	2.37%	$59.35	10.96%
12	5,000	$11.00	$1,061.00	$1,072.00	$ 3,922.00	$4,994.00	$13.50	$ 1,174.70	$1,188.20	$ 3,922.00	$5,110.20	$116.20	2.33%	$116.20	10.84%
13	7,500	$11.00	$1,591.50	$1,602.50	$ 5,883.00	$7,485.50	$13.50	$ 1,762.05	$1,775.55	$ 5,883.00	$7,658.55	$173.05	2.31%	$173.05	10.80%
14	10,000	$11.00	$2,122.00	$2,133.00	$ 7,844.00	$9,977.00	$13.50	$ 2,349.40	$2,362.90	$ 7,844.00	$10,206.90	$229.90	2.30%	$229.90	10.78%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Larve Volume Industrial Service (I-32)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$85.00	$100.00	A
2	Distribution Margin Therms	$ 0.0864	$ 0.0958	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	10,001	$85.00	$ 864.09	$949.09	$ 7,844.78	$8,793.87	$100.00	$ 957.69	$1,057.69	$ 7,844.78	$8,902.47	$108.60	1.23%	$108.60	11.44%
7	15,000	$85.00	$ 1,296.00	$1,381.00	$ 11,766.00	$13,147.00	$100.00	$ 1,436.40	$1,536.40	$ 11,766.00	$13,302.40	$155.40	1.18%	$155.40	11.25%
8	20,000	$85.00	$ 1,728.00	$1,813.00	$ 15,688.00	$17,501.00	$100.00	$ 1,915.20	$2,015.20	$ 15,688.00	$17,703.20	$202.20	1.16%	$202.20	11.15%
9	30,000	$85.00	$ 2,592.00	$2,677.00	$ 23,532.00	$26,209.00	$100.00	$ 2,872.79	$2,972.79	$ 23,532.00	$26,504.79	$295.79	1.13%	$295.79	11.05%
10	50,000	$85.00	$ 4,320.00	$4,405.00	$ 39,220.00	$43,625.00	$100.00	$ 4,787.99	$4,887.99	$ 39,220.00	$44,107.99	$482.99	1.11%	$482.99	10.96%
11	75,000	$85.00	$ 6,480.00	$6,565.00	$ 58,830.00	$65,395.00	$100.00	$ 7,181.98	$7,281.98	$ 58,830.00	$66,111.98	$716.98	1.10%	$716.98	10.92%
12	100,000	$85.00	$ 8,640.00	$8,725.00	$ 78,440.00	$87,165.00	$100.00	$ 9,575.98	$9,675.98	$ 78,440.00	$88,115.98	$950.98	1.09%	$950.98	10.90%
13	125,000	$85.00	$ 10,800.00	$10,885.00	$ 98,050.00	$108,935.00	$100.00	$ 11,969.97	$12,069.97	$ 98,050.00	$110,119.97	$1,184.97	1.09%	$1,184.97	10.89%
14	150,000	$85.00	$ 12,960.00	$13,045.00	$ 117,660.00	$130,705.00	$100.00	$ 14,363.97	$14,463.97	$ 117,660.00	$132,123.97	$1,418.97	1.09%	$1,418.97	10.88%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Small Volume Public Authority (PA-40)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2354	$ 0.2582	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 11.77	$22.77	$ 39.22	$61.99	$13.50	$ 12.91	$26.41	$ 39.22	$65.63	$3.64	5.87%	$3.64	15.99%
7	100	$11.00	$ 23.54	$34.54	$ 78.44	$112.98	$13.50	$ 25.82	$39.32	$ 78.44	$117.76	$4.78	4.23%	$4.78	13.84%
8	500	$11.00	$ 117.70	$128.70	$ 392.20	$520.90	$13.50	$ 129.12	$142.62	$ 392.20	$534.82	$13.92	2.67%	$13.92	10.82%
9	1,000	$11.00	$ 235.40	$246.40	$ 784.40	$1,030.80	$13.50	$ 258.23	$271.73	$ 784.40	$1,056.13	$25.33	2.46%	$25.33	10.28%
10	1,500	$11.00	$ 353.10	$364.10	$ 1,176.60	$1,540.70	$13.50	$ 387.35	$400.85	$ 1,176.60	$1,577.45	$36.75	2.39%	$36.75	10.09%
11	2,500	$11.00	$ 588.50	$599.50	$ 1,961.00	$2,560.50	$13.50	$ 645.58	$659.08	$ 1,961.00	$2,620.08	$59.58	2.33%	$59.58	9.94%
12	5,000	$11.00	$1,177.00	$1,188.00	$ 3,922.00	$5,110.00	$13.50	$ 1,291.15	$1,304.65	$ 3,922.00	$5,226.65	$116.65	2.28%	$116.65	9.82%
13	7,500	$11.00	$1,765.50	$1,776.50	$ 5,883.00	$7,659.50	$13.50	$ 1,936.73	$1,950.23	$ 5,883.00	$7,833.23	$173.73	2.27%	$173.73	9.78%
14	10,000	$11.00	$2,354.00	$2,365.00	$ 7,844.00	$10,209.00	$13.50	$ 2,582.30	$2,595.80	$ 7,844.00	$10,439.80	$230.80	2.26%	$230.80	9.76%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Large Volume Public Authority (PA-42)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge	$85.00	$100.00	A
2	Distribution Margin Therms	$ 0.1084	$ 0.1201	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

		Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Average Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	10,001	$85.00	$ 1,084.11	$1,169.11	$ 7,844.78	$9,013.89	$100.00	$ 1,201.23	$1,301.23	$ 7,844.78	$9,146.01	$132.12	1.47%	$132.12	11.30%
7	15,000	$85.00	$ 1,626.00	$1,711.00	$ 11,766.00	$13,477.00	$100.00	$ 1,801.67	$1,901.67	$ 11,766.00	$13,667.67	$190.67	1.41%	$190.67	11.14%
8	20,000	$85.00	$ 2,168.00	$2,253.00	$ 15,688.00	$17,941.00	$100.00	$ 2,402.22	$2,502.22	$ 15,688.00	$18,190.22	$249.22	1.39%	$249.22	11.06%
9	30,000	$85.00	$ 3,252.00	$3,337.00	$ 23,532.00	$26,869.00	$100.00	$ 3,603.33	$3,703.33	$ 23,532.00	$27,235.33	$366.33	1.36%	$366.33	10.98%
10	50,000	$85.00	$ 5,420.00	$5,505.00	$ 39,220.00	$44,725.00	$100.00	$ 6,005.55	$6,105.55	$ 39,220.00	$45,325.55	$600.55	1.34%	$600.55	10.91%
11	75,000	$85.00	$ 8,130.00	$8,215.00	$ 58,830.00	$67,045.00	$100.00	$ 9,008.33	$9,108.33	$ 58,830.00	$67,938.33	$893.33	1.33%	$893.33	10.87%
12	100,000	$85.00	$ 10,840.00	$10,925.00	$ 78,440.00	$89,365.00	$100.00	$ 12,011.10	$12,111.10	$ 78,440.00	$90,551.10	$1,186.10	1.33%	$1,186.10	10.86%
13	125,000	$85.00	$ 13,550.00	$13,635.00	$ 98,050.00	$111,685.00	$100.00	$ 15,013.88	$15,113.88	$ 98,050.00	$113,163.88	$1,478.88	1.32%	$1,478.88	10.85%
14	150,000	$85.00	$ 16,260.00	$16,345.00	$ 117,660.00	$134,005.00	$100.00	$ 18,016.65	$18,116.65	$ 117,660.00	$135,776.65	$1,771.65	1.32%	$1,771.65	10.84%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Special Gas Light Service (PA-44)

Line	**Rate Component**	Present Rates	Staff Proposed	Increase $	Note
1	Customer Charge Lighting Group A	$13.57	**$15.05**	$1.48	A
2	Customer Charge Lighting Group B	$16.28	**$18.06**	$1.78	A

	Annual Bill Impact	Present	Proposed	Increase $	Increase %
3	Customer Charge Lighting Group A	$162.84	$180.59	$17.75	10.90%
4	Customer Charge Lighting Group B	$195.36	$216.66	$21.30	10.90%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended December 31, 2005

Irrigation Service (IR-60)

Line	Rate Component	Present Rates	Staff Proposed	Notes
1	Customer Charge (Sum: Apr-Nov)	$11.00	$13.50	A
2	Distribution Margin Therms	$ 0.2876	$0.3179	A
3	Feb 2007 PGA Cost	$ 0.3844	$ 0.3844	B
4	Base gas cost	$ 0.4000	$ 0.4000	B
5	Gas Cost Subtotal	$ 0.7844	$ 0.7844	L3+L4

	Average	Present Rates					Proposed Rates					Total Bill		Base Rates Only	
	Therms Per Month	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Customer Charge	Distribution Margin	Base Rates	Gas Cost	Total Bill	Proposed Increase $	Proposed Increase %	Proposed Increase $	Proposed Increase %
6	50	$11.00	$ 14.38	$25.38	$ 39.22	$64.60	$13.50	$ 15.90	$29.40	$ 39.22	$68.62	$4.02	6.22%	$4.02	15.84%
7	100	$11.00	$ 28.76	$39.76	$ 78.44	$118.20	$13.50	$ 31.79	$45.29	$ 78.44	$123.73	$5.53	4.68%	$5.53	13.91%
8	500	$11.00	$ 143.80	$154.80	$ 392.20	$547.00	$13.50	$ 158.95	$172.45	$ 392.20	$564.65	$17.65	3.23%	$17.65	11.40%
9	1,000	$11.00	$ 287.60	$298.60	$ 784.40	$1,083.00	$13.50	$ 317.90	$331.40	$ 784.40	$1,115.80	$32.80	3.03%	$32.80	10.98%
10	1,500	$11.00	$ 431.40	$442.40	$ 1,176.60	$1,619.00	$13.50	$ 476.85	$490.35	$ 1,176.60	$1,666.95	$47.95	2.96%	$47.95	10.84%
11	2,500	$11.00	$ 719.00	$730.00	$ 1,961.00	$2,691.00	$13.50	$ 794.75	$808.25	$ 1,961.00	$2,769.25	$78.25	2.91%	$78.25	10.72%
12	5,000	$11.00	$1,438.00	$1,449.00	$ 3,922.00	$5,371.00	$13.50	$ 1,589.50	$1,603.00	$ 3,922.00	$5,525.00	$154.00	2.87%	$154.00	10.63%
13	7,500	$11.00	$2,157.00	$2,168.00	$ 5,883.00	$8,051.00	$13.50	$ 2,384.25	$2,397.75	$ 5,883.00	$8,280.75	$229.75	2.85%	$229.75	10.60%
14	10,000	$11.00	$2,876.00	$2,887.00	$ 7,844.00	$10,731.00	$13.50	$ 3,179.00	$3,192.50	$ 7,844.00	$11,036.50	$305.50	2.85%	$305.50	10.58%

Notes
A Staff Proof of Revenue. See Attachment RCS-S1, Schedule RD-1
B Cost of Gas Inputs workpaper

EXHIBIT
S-28
admitted

Corrections to the Prefiled Testimony of Staff Witness Ralph C. Smith

Page	Line	Reads	Should Read
Direct Testimony (Filed February 9, 2007)			
28	11	pro reduction	pro forma reduction
39	11	This adjustment increases	This adjustment decreases
39	12	and decreases	and increases

Please note that the Attachment RCS-2 has been revised in
Attachments RCS-2S filed wth Mr. Smith's surrebuttal testimony.

Supplemental Testimony (Filed February 23, 2007)
Please note that the Attachments RCS-S1 and RCS-S2 have been revised in
Attachments RCS-S1(R) and RCS-S2(R) filed wth Mr. Smith's surrebuttal testimony.

Surrebuttal Testimony (Filed April 4, 2007)			
2	17	Exhibit RCS-2S	Attachment RCS-2S
6	5	Exhibit RCS-2S	Attachment RCS-2S
6	8	Exhibit RCS-2S	Attachment RCS-2S
7	3	Exhibit RCSs-2S	Attachment RCS-2S
8	22	caution Against	caution against
9	26	for that matter virtually	for that matter, in virtually
17	18	prohibition Against	prohibition against
20	5	Exhibit RCS-2S	Attachment RCS-2S
20	11	Exhibit RCS-2S	Attachment RCS-2S
20	12	Exhibit RCS-2S	Attachment RCS-2S
24	6	added $16,691 the net	added $16,691. The net
27	17	pages	page
32	15	"although	"Although
32	17	southwest gas	Southwest Gas
34	25	UNS Gas witness dukes	UNS Gas witness Dukes
36	10	southwest gas	Southwest Gas
36	12	[table is missing - this table should appear on line 12]	

Utility:	UNS Gas, Inc.	Southwest Gas Corp.
Docket:	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	December 31, 2005	August 31, 2004
New Rates Effective:	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years	3 to 4 years
Assessment Rate Used:	24 percent	24.5 percent
Corresponding Effective Year:	2007	2006

37	13	southwest gas	Southwest Gas
37	15	southwest gas	Southwest Gas
38	13	UNS Gas' 2005 AGA dues for 2005	UNS Gas' AGA dues for 2005
39	1	city gas company	City Gas Company
42	20	southwest gas corporation	Southwest Gas Corporation
43	1	citizens utilities	Citizens Utilities
43	9	southwest gas	Southwest Gas
43	21	southwest gas	Southwest Gas
43	22	southwest gas	Southwest Gas
43	23	southwest gas	Southwest Gas
44	10	cares program	Cares program

EXHIBIT
ALL-STATE LEGAL®
S-30
admitted

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.2 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b:

a. Please provide all cost studies and economic analysis that the Company has relating to its proposed increase in reimbursement from the customer to the Company for gas service line from $8 to $16 per foot.

b. Please provide all cost studies and economic analysis that the Company has relating to its proposed increase to $12 per foot for customers who provide the trench for the service line on their own property.

c. Please provide the complete documentation and calculations relied upon by the Company for its $16 per foot current costs (Smith, page 19, line 7-8) and $12 (Smith page 19, line 12).

d. Please identify for each year of UNS Gas ownership through 2006, the annual amount of customer reimbursement for gas service line connections, the annual cost incurred by UNS Gas for such connections, the amount of billings to customers for such connections, and the amount of feet installed.

RESPONSE:

a. Please see STF 13.2 on the enclosed CD for all cost studies and the economic analysis the Company has relating to its proposed increase in reimbursement from the customer to the Company for a gas service line from $8 to $16 per foot. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

b. Please see STF 13.2 on the enclosed CD for all cost studies and economic analysis that the Company has relating to its proposed increase to $12 per foot for customers who provide the trench for the service line on their own property. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

c. Please see STF 13.2 on the enclosed CD for the complete documentation and calculations relied upon by the Company for its $16 per foot current costs (Smith, page 19, line 7-8) and $12 (Smith page 19, line 12). The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

d. Please see STF 13.2 on the enclosed CD for UNS Gas ownership through 2006, the annual amount of customer reimbursement for gas service line connections, the annual cost incurred by UNS Gas for such connections, the amount of billings to customers for such connections, and the amount of feet installed. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

2005 Most Common Serviceline Installations

						Installation with Trench			Installation Trench Provided		
% by Size	Description		Footage	# of Services	Ave Length	Per Foot Cost	Estimated Cost	Extended Cost of Serv	Per Foot Cost	Estimated Cost	Extended Cost of Serv
76%	Plastic	1/2 inch	182689	5,018	36	$ 16.60	$ 597	$ 3,032,048	$ 12.28	$ 442	$ 2,244,011
16%	Plastic	3/4 inch	37456	442	85	$ 13.23	$ 1,125	$ 495,583	$ 8.29	$ 705	$ 310,551
2%	Plastic	1 1/4 inch	4200	58	72						
1%	Plastic	2 inch	1469	14	105						
0%	Plastic	4 inch	255	2	128						
0%	Steel	1/2 inch									
6%	Steel	3/4 inch	13421	284	47	$ 19.43	$ 918	$ 260,800	$ 16.98	$ 815	$ 227,933
0%	Steel	1 inch	854	12	71						
0%	Steel	1 1/4 inch	368	1	368						
0%	Steel	2 inch	266	5	53						
0%	Steel	4 inch	36	2	18						
100%	Average of most common pipe		233,566	5,744	56	$ 16.22	$ 2,640	$ 3,788,430	$ 11.91	$ 1,962	$ 2,782,495

% by Group

99.16%	Typical Small Service (< 2")	238,988	5,815	41	$ 64.25	$2,640.43
0.84%	Typical Large Service (>= 2")	2,026	23	88	$ -	$ -
100.00%	Total Footage	241,014	5,838	41	$ 63.96	$2,640.43

New Customers in 2005

Rate Schedule	#	% by Rate Class
10	5796	95.52%
20	268	4.42%
22	4	0.07%
TOTAL	6068	100.00%

EXHIBIT
ALL-STATE LEGAL®
S-31
admitted

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.3 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. How do UNS Gas' proposed service line connection charges compare with those currently in effect by other Arizona gas distribution utilities?

b. Please provide all comparative information the Company has with respect to how UNS Gas' proposed service line connection charges compare with those currently in effect by other Arizona gas distribution utilities.

RESPONSE: UNS Gas relied on estimates to determine its costs and did not use comparative information from other Arizona distribution utilities with respect to its proposed service line connection charges. UNS Gas does not have the requested comparative information in its possession.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.4 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. Please identify and provide specific details for the 10 most costly residential line connections in 2006 under current rules. Include calculations of the related Incremental Contribution Method and any related "economic feasibility" calculations.

b. For each line connection identified in response to part a, please show what the cost to the customer would be under UNS Gas' proposed rules and regulations.

RESPONSE: UNS Gas uses blanket service projects and tasks, therefore the information concerning the ten most costly is not available in its system.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.5 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. Please identify and provide specific details for the 10 most costly line connections in 2006 under current rules for non-residential customers. Include calculations of the related Incremental Contribution Method and any related "economic feasibility" calculations.

b. For each line connection identified in response to part a, please show what the cost to the customer would be under UNS Gas' proposed rules and regulations.

RESPONSE: UNS Gas uses blanket service projects and tasks, therefore the information concerning the ten most costly line connections is not available in its system.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

Regulatory Research Associates
An SNLEnergy Company
REGULATORY FOCUS

January 30, 2007

MAJOR RATE CASE DECISIONS--JANUARY 2005-DECEMBER 2006
SUPPLEMENTAL STUDY

This Supplemental Study was prepared in conjunction with the Regulatory Study entitled *Major Rate Case Decisions--January 1990-December 2006* that will be uploaded to our website later today. The Supplemental Study contains chronological listings of all electric and gas cases for the years 2005 and 2006. These listings, with key data concerning each case, appear on pages 5 through 10 of this report. Tables summarizing cases decided in the last 11 years appear on pages 2 and 3. The average return on equity (ROE) authorized electric utilities in 2006 approximated 10.4%, compared to 10.5% in 2005. There were 25 electric ROE determinations in 2006, and 29 in 2005. The average ROE authorized gas utilities also approximated 10.4% in 2006, compared to 10.5% in 2005. There were 15 gas cases that included an ROE determination in 2006, and 26 in 2005. We note that these ROEs are simple, non-weighted averages. Not included in these averages is a September 20, 2006 steam rate case decision for Consolidated Edison of New York, in which the New York Public Service Commission adopted a settlement that incorporates a 9.8% return on common equity (48% of capital) and a 7.74% return on rate base.

After reaching a low in the late-1990's and early-2000's, the number of equity return determinations for energy companies has generally increased over the last several years. Increased costs (especially medical insurance and pension expenses), the need for generation and delivery system infrastructure upgrades and expansion at many companies, and the expiration of restructuring-related rate freezes argue for a continuation of the increased level of rate case activity over the next several years. However, relatively low inflation and interest rates, competitive pressures, technological improvements, the use of settlements that do not specify return parameters, and a reduced number of companies due to mergers, may prevent the number of rate cases and equity return determinations from significantly increasing further. We note that electric industry restructuring in many states has led to the unbundling of rates, with state commissions authorizing revenue requirement and return parameters for distribution and/or transmission operations only (which we footnote in our chronology), thus complicating historical data comparability.

The individual electric and gas cases listed on pages 5 through 10 are presented with the decision date shown first, followed by the company name, the abbreviation of the state issuing the decision, the authorized rate of return (ROR) and ROE, and the common equity component of the adopted capital structure. If the capital structure included cost-free capital or investment tax credit balances at the overall rate of return, an asterisk (*) follows the number in this column. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base valuation, and the amount of the permanent rate change authorized. Fuel adjustment clause rate changes are not reflected in this study.

(Text continued on page 4.)

EXHIBIT
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admitted

Average Equity Returns Authorized January 1996 - December 2006

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities
1996	Full Year	11.39 (22)	11.19 (20)
1997	Full Year	11.40 (11)	11.29 (13)
1998	Full Year	11.66 (10)	11.51 (10)
1999	Full Year	10.77 (20)	10.66 (9)
2000	1st Quarter	11.06 (5)	10.71 (1)
	2nd Quarter	11.11 (2)	11.08 (4)
	3rd Quarter	11.68 (2)	11.33 (5)
	4th Quarter	12.08 (3)	12.50 (2)
2000	Full Year	11.43 (12)	11.39 (12)
2001	1st Quarter	11.38 (2)	11.16 (4)
	2nd Quarter	10.88 (2)	10.75 (1)
	3rd Quarter	10.78 (8)	--- (0)
	4th Quarter	11.50 (6)	10.65 (2)
2001	Full Year	11.09 (18)	10.95 (7)
2002	1st Quarter	10.87 (5)	10.67 (3)
	2nd Quarter	11.41 (6)	11.64 (4)
	3rd Quarter	11.06 (4)	11.50 (3)
	4th Quarter	11.20 (7)	10.78 (11)
2002	Full Year	11.16 (22)	11.03 (21)
2003	1st Quarter	11.47 (7)	11.38 (5)
	2nd Quarter	11.16 (4)	11.36 (4)
	3rd Quarter	9.95 (5)	10.61 (5)
	4th Quarter	11.09 (6)	10.84 (11)
2003	Full Year	10.97 (22)	10.99 (25)
2004	1st Quarter	11.00 (3)	11.10 (4)
	2nd Quarter	10.54 (6)	10.25 (2)
	3rd Quarter	10.33 (2)	10.37 (8)
	4th Quarter	10.91 (8)	10.66 (6)
2004	Full Year	10.75 (19)	10.59 (20)
2005	1st Quarter	10.51 (7)	10.65 (2)
	2nd Quarter	10.05 (7)	10.54 (5)
	3rd Quarter	10.84 (4)	10.47 (5)
	4th Quarter	10.75 (11)	10.40 (14)
2005	Full Year	10.54 (29)	10.46 (26)
2006	1st Quarter	10.38 (3)	10.63 (6)
	2nd Quarter	10.69 (5)	10.50 (2)
	3rd Quarter	10.06 (7)	10.45 (3)
	4th Quarter	10.39 (10)	10.13 (4)
2006	Full Year	10.36 (25)	10.44 (15)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1996	Full Year	9.21 (20)	11.39 (22)	44.34 (20)	-5.6 (38)
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	313.8 (22)
2004	Full Year	8.44 (18)	10.75 (19)	46.84 (17)	1,092.6 (30)
2005	1st Quarter	8.57 (6)	10.51 (7)	44.55 (7)	482.1 (8)
	2nd Quarter	8.27 (5)	10.05 (7)	48.30 (5)	180.2 (9)
	3rd Quarter	7.78 (4)	10.84 (4)	43.58 (4)	40.2 (5)
	4th Quarter	8.37 (11)	10.75 (11)	48.55 (11)	671.2 (14)
2005	Full Year	8.30 (26)	10.54 (29)	46.73 (27)	1,373.7 (36)
2006	1st Quarter	8.13 (3)	10.38 (3)	50.25 (3)	444.6 (9)
	2nd Quarter	8.02 (5)	10.69 (5)	45.40 (4)	130.7 (6)
	3rd Quarter	7.89 (7)	10.06 (7)	46.86 (6)	251.3 (9)
	4th Quarter	8.55 (9)	10.39 (10)	50.59 (10)	638.4 (18)
2006	Full Year	8.20 (24)	10.36 (25)	48.67 (23)	1,465.0 (42)

Gas Utilities--Summary Table*

1996	Full Year	9.25 (23)	11.19 (20)	47.69 (19)	193.4 (34)
1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)
2004	Full Year	8.34 (21)	10.59 (20)	45.90 (20)	303.5 (31)
2005	1st Quarter	8.19 (3)	10.65 (2)	43.00 (1)	50.8 (4)
	2nd Quarter	8.17 (5)	10.54 (5)	47.69 (4)	99.5 (6)
	3rd Quarter	8.15 (6)	10.47 (5)	49.54 (5)	75.3 (7)
	4th Quarter	8.33 (15)	10.40 (14)	49.03 (14)	232.8 (17)
2005	Full Year	8.25 (29)	10.46 (26)	48.66 (24)	458.4 (34)
2006	1st Quarter	8.62 (6)	10.63 (6)	51.18 (6)	138.7 (6)
	2nd Quarter	7.98 (1)	10.50 (2)	44.38 (2)	-4.8 (2)
	3rd Quarter	8.15 (3)	10.45 (3)	47.19 (3)	38.8 (5)
	4th Quarter	7.82 (5)	10.13 (4)	44.15 (4)	268.5 (11)
2006	Full Year	8.22 (15)	10.44 (15)	47.60 (15)	441.2 (24)

* Number of observations in each period indicated in parentheses.

The table on page 2 shows the average ROE authorized annually since 1996 and by quarter since 2000, in major electric and gas rate decisions, followed by the number of observations in each period. The tables on page 3 show the composite electric and gas industry data for all the cases included in the chronology of this and earlier reports, summarized annually since 1996 and by quarter for the past eight quarters.

The table below tracks the average equity return authorized for all electric and gas rate cases combined, by year, for the last 17 years. As the table reveals, since 1990 authorized ROEs have generally trended downward, reflecting the significant decline in interest rates that has occurred over this time frame. The combined average equity returns authorized for all utilities in each of the years 1990 through 2006, and the number of observations for each year are as follows:

1990	12.69%	(75)	1999	10.74%	(29)
1991	12.51	(80)	2000	11.41	(24)
1992	12.06	(77)	2001	11.05	(25)
1993	11.37	(77)	2002	11.10	(43)
1994	11.34	(59)	2003	10.98	(47)
1995	11.51	(49)	2004	10.67	(39)
1996	11.29	(42)	2005	10.50	(55)
1997	11.34	(24)	2006	10.39	(40)
1998	11.59	(20)			

Dennis Sperduto

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/6/05	South Carolina Electric & Gas (SC)	8.64	10.70	50.31	12/04-YE	41.4
1/28/05	Aquila Networks-WPK (KS)	8.73	10.50	33.63	12/03-YE	7.4
2/18/05	Puget Sound Energy (WA)	8.40	10.30	43.00	9/03-A	56.6
2/25/05	PacifiCorp (UT)	8.37	10.50	47.80	3/06	51.0 (B)
3/10/05	Empire District Electric (MO)	9.18	11.00	49.14	12/03-YE	25.7 (B)
3/18/05	Dominion North Carolina Power (NC)	---	---	---	12/03	-12.0 (B)
3/24/05	Consolidated Edison of New York (NY)	8.08	10.30	48.00	3/06-A	325.0 (B,Z,TD)
3/31/05	Texas-New Mexico Power (TX)	---	10.25	40.00	---	-13.0 (B,Di)
2005	***1ST QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.57** **6**	**10.51** **7**	**44.55** **7**		**482.1** **8**
4/4/05	Central Vermont Public Service (VT)	8.14	10.00	55.53	12/03-A	-7.2 (R)
4/7/05	Arizona Public Service (AZ)	7.80	10.25	45.00 (Hy)	12/02-YE	67.6 (B)
5/2/05	Public Service Co. of Oklahoma (OK)	---	---	---	6/03-YE	-6.9 (B)
5/18/05	Entergy Louisiana (LA)	8.76	10.25	48.73	12/02-A	0.0 (B)
5/18/05	Wisconsin Electric Power (WI)	---	---	---	12/05-A	59.7
5/25/05	Savannah Electric and Power (GA)	---	10.75	---	---	9.6 (B)
5/26/05	Atlantic City Electric (NJ)	8.14	9.75	46.22	12/02-YE	-3.1 (Di,B)
5/26/05	Idaho Power (ID)	---	---	---	---	9.4
6/1/05	Jersey Central Power & Light (NJ)	8.50	9.75	46.00	12/02-YE	51.1 (Di,B)
6/8/05	Public Service New Hampshire (NH)	---	9.62 (R, Gn)	---	---	---
2005	***2ND QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.27** **5**	**10.05** **7**	**48.30** **5**		**180.2** **9**
7/19/05	Wisconsin Power and Light (WI)	9.41 (G)	11.50	61.75	6/06-A/P	18.6
7/22/05	PacifiCorp (ID)	---	---	---	---	5.8 (B)
8/5/05	Cap Rock Energy (TX)	6.17	11.75	25.00 (Hy)	9/03-YE	-1.3
8/15/05	AEP Texas Central (TX)	7.48	10.13	40.00	6/03-YE	-8.8 (TD,B)
9/28/05	PacifiCorp (OR)	8.06	10.00	47.56	12/06-A	25.9 (Bp)
2005	***3RD QUARTER AVERAGES/TOTAL OBSERVATIONS***	**7.78** **4**	**10.84** **4**	**43.58** **4**		**40.2** **5**
12/9/05	Empire District Electric (KS)	---	---	---	---	2.2 (B)
12/12/05	Madison Gas and Electric (WI)	8.88 (G)	11.00	56.65	12/06-A/P	35.9
12/13/05	OGE Electric Service(OK)	8.66	10.75	55.69	12/04-YE	42.3
12/16/05	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/06	3.3
12/16/05	San Diego Gas & Electric (CA)	8.23	10.70	49.00	12/06	0.0
12/16/05	Southern California Edison (CA)	8.77	11.60	48.00	12/06	-26.4
12/21/05	Cincinnati Gas & Electric (OH)	8.24	10.29	47.53	6/05-A	51.5 (Di,B)
12/21/05	Avista (WA)	9.11	10.40	40.00	12/04-A	22.1 (B)
12/22/05	Consumers Energy (MI)	6.78	11.15	36.31 *	12/03-A	177.4
12/22/05	Wisconsin Public Service (WI)	8.82 (G)	11.00	59.73	12/06-A/P	79.9
12/28/05	Westar Energy North (KS)	7.89	10.00	44.59	12/04-YE	24.2
12/28/05	Kansas Gas and Electric (KS)	7.89	10.00	44.59	12/04-YE	-21.2
12/28/05	Dayton Power & Light (OH)	---	---	---	---	250.0 (E,B,Z)
12/30/05	NSTAR Electric (MA)	---	---	---	---	30.0 (B,Di,1)
2005	***4TH QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.37** **11**	**10.75** **11**	**48.55** **11**		**671.2** **14**
2005	***FULL-YEAR AVERAGES/TOTAL OBSERVATIONS***	**8.30** **26**	**10.54** **29**	**46.73** **27**		**1373.7** **36**

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/06	Northern States Power (WI)	8.94 (G)	11.00	53.66	12/06-A	43.4
1/25/06	Wisconsin Electric Power (WI)	---	---	---	---	229.7 (2)
1/27/06	United Illuminating (CT)	6.88 (3)	9.75	48.00	12/04-A	41.2 (R,Di,Z,3)
2/23/06	Aquila Networks-MPS (MO)	---	---	---	---	22.4 (B)
2/23/06	Aquila Networks-L&P (MO)	---	---	---	---	3.9 (B)
3/3/06	Interstate Power and Light (MN)	8.58	10.39	49.10	12/04-A	1.2 (I,B)
3/14/06	Kentucky Power (KY)	---	---	---	---	41.0 (B)
3/24/06	PacifiCorp (WY)	---	---	---	---	25.0 (B,Z)
3/29/06	Entergy Gulf States (LA)	---	---	---	---	36.8 (I,B)
2006	***1ST QUARTER: AVERAGES/TOTAL***	**8.13**	**10.38**	**50.25**		**444.6**
	MEDIAN	**8.58**	**10.39**	**49.10**		---
	OBSERVATIONS	**3**	**3**	**3**		**9**
4/17/06	PacifiCorp (WA)	8.10	10.20	46.00	9/04-A	0.0
4/18/06	MidAmerican Energy (IA)	---	11.90 (4)	---	---	---
4/26/06	Sierra Pacific Power (NV)	8.96	10.60	40.76	5/05-YE	-14.0
5/12/06	Idaho Power (ID)	8.10	---	---	12/05	18.1 (B)
5/17/06	Southern California Edison (CA)	---	---	---	12/06-A	133.9 (5)
6/6/06	Delmarva Power & Light (DE)	7.17	10.00	47.72	3/05-A	-11.1 (Di)
6/27/06	Upper Peninsula Power (MI)	7.75	10.75	47.12 *	12/06	3.8 (B)
2006	***2ND QUARTER: AVERAGES/TOTAL***	**8.02**	**10.69**	**45.40**		**130.7**
	MEDIAN	**8.10**	**10.60**	**46.56**		---
	OBSERVATIONS	**5**	**5**	**4**		**6**
7/6/06	Maine Public Service (ME)	8.45	10.20	50.00	12/05	1.8 (B,Di)
7/24/06	Central Hudson Gas & Electric (NY)	7.05 (6)	9.60	45.00	3/06-A	53.7 (B,Z,TD)
7/26/06	Appalachian Power (WV)	7.60	10.50	---	12/04-A	111.7 (B,Z)
7/28/06	Commonwealth Edison (IL)	8.01	10.05	42.86	12/04-YE	82.6 (R,TD,7)
8/23/06	New York State Electric & Gas (NY)	7.18	9.55	41.60	12/07-A	-36.3 (TD)
8/31/06	Detroit Edison (MI)	---	---	---	---	-78.8 (B,Z)
9/1/06	Northern States Power (MN)	8.81	10.54	51.67	12/06-A	131.5 (I,8)
9/5/06	CenterPoint Energy Houston Electric (TX)	---	---	---	12/05	-57.9 (B,TD)
9/14/06	PacifiCorp (OR)	8.16	10.00	50.00	12/07-A	43.0 (B,7)
2006	***3RD QUARTER: AVERAGES/TOTAL***	**7.89**	**10.06**	**46.86**		**251.3**
	MEDIAN	**8.01**	**10.05**	**47.50**		---
	OBSERVATIONS	**7**	**7**	**6**		**9**
10/6/06	Unitil Energy Systems (NH)	8.70	9.67	43.10	6/05-YE	2.8 (B,Di,Z)
10/27/06	Entergy New Orleans (LA)	---	---	---	---	3.9 (B,9)

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
11/21/06	Delmarva Power & Light (DE)	---	---	---	---	-12.0 (B,I,Tr)
11/21/06	Central Illinois Light (IL)	7.94	10.12	45.57	12/04-YE	20.7 (TD)
11/21/06	Central Illinois Public Service (IL)	8.06	10.08	48.92	12/04-YE	-8.0 (TD)
11/21/06	Illinois Power (IL)	8.33	10.08	51.56	12/04-YE	84.0 (TD)
12/1/06	Duquesne Light (PA)	---	---	45.00	12/06	117.0 (B,Di)
12/1/06	PacifiCorp (UT)	---	10.25	---	---	115.0 (B,Z)
12/1/06	Public Service of Colorado (CO)	8.85	10.50	60.00	---	107.0 (B)
12/4/06	Kansas City Power & Light (KS)	---	---	---	---	29.0 (B)
12/7/06	Central Vermont Public Service (VT)	8.55	10.75	55.57	12/05-A	10.8 (B)
12/14/06	Western Massachusetts Electric (MA)	---	---	---	---	4.0 (B,Di,Z)
12/18/06	PacifiCorp (ID)	---	---	---	---	8.3 (B)
12/21/06	Duke Energy Kentucky (KY)	---	---	---	---	49.0 (B)
12/21/06	Empire District Electric (MO)	9.07	10.90	49.74	12/05-YE	29.4
12/21/06	Kansas City Power & Light (MO)	8.83 (E)	11.25	53.69	12/05-YE	50.6
12/22/06	Green Mountain Power (VT)	8.65	10.25	52.76	12/05-A	19.0 (B)
12/28/06	Black Hills Power (SD)	---	---	---	---	7.9 (B)
2006	***4TH QUARTER: AVERAGES/TOTAL***	**8.55**	**10.39**	**50.59**		**638.4**
	MEDIAN	**8.65**	**10.25**	**50.65**		**---**
	OBSERVATIONS	**9**	**10**	**10**		**18**
2006	***FULL YEAR: AVERAGES/TOTAL***	**8.20**	**10.36**	**48.67**		**1465.0**
	MEDIAN	**8.25**	**10.25**	**48.92**		**---**
	OBSERVATIONS	**24**	**25**	**23**		**42**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/05	Avista Corporation (WA)	8.68	---	---	---	5.4 (B)
2/18/05	Puget Sound Energy (WA)	8.40	10.30	43.00	9/03-A	26.3
3/29/05	SEMCO Energy Gas (MI)	7.49	11.00	---	12/05	7.1 (B)
3/30/05	National Fuel Gas Distribution (PA)	---	---	---	5/04-YE	12.0 (B)
2005	***1ST QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.19** **3**	**10.65** **2**	**43.00** **1**		**50.8** **4**
4/13/05	Vectren Energy Delivery of Ohio (OH)	8.94	10.60	48.10 (E)	12/04-A	15.7
4/28/05	Michigan Consolidated Gas (MI)	7.19	11.00	39.31 *	12/02-A	60.8 (I)
5/4/05	Aquila Networks-KGO (KS)	---	---	---	---	2.7 (B)
5/17/05	AmerenIP (IL)	8.18	10.00	53.09	12/03-YE	11.3 (Bp)
6/8/05	CenterPoint Energy Minnegasco (MN)	8.03	10.18	50.27	9/05-A	9.0 (I,B)
6/10/05	Atlanta Gas Light (GA)	8.53 (R)	10.90 (R)	---	11/05-A	0.0 (R,B,10)
2005	***2ND QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.17** **5**	**10.54** **5**	**47.69** **4**		**99.5** **6**
7/6/05	Entergy Gulf States (LA)	8.11	10.50	47.52	9/03-A	5.8 (B)
7/19/05	Wisconsin Power and Light (WI)	9.41 (G)	11.50	61.75	6/06-A/P	2.0
7/22/05	National Fuel Gas Distribution (NY)	---	---	---	7/06-A	21.0 (B)
8/11/05	Northern States Power (MN)	8.76	10.40	50.24	12/04-A	5.8 (I,B)
8/24/05	Mountaineer Gas (WV)	8.43	---	---	12/03-YE	17.3 (B,Z)
9/19/05	CenterPoint Energy Arkansas Gas (AR)	5.31	9.45	31.80 *	4/04-YE	-11.3
9/30/05	Northern Illinois Gas (IL)	8.85	10.51	56.37	12/05-A	34.7 (11)
2005	***3RD QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.15** **6**	**10.47** **5**	**49.54** **5**		**75.3** **7**
10/3/05	Laclede Gas (MO)	---	---	---	---	8.5 (B)
10/4/05	Oklahoma Natural Gas (OK)	8.74	9.90	46.76	7/04-YE	57.5 (B)
10/14/05	Interstate Power & Light (IA)	8.68	10.40	49.35	12/04-A	14.0 (I,B)
10/21/05	Dominion Hope Gas (WV)	---	---	---	12/04-YE	4.0 (B)
10/31/05	South Carolina Electric & Gas (SC)	8.43	10.25	50.75	12/04-YE	22.9 (B)
11/2/05	Arkansas Western Gas (AR)	5.93	9.70	33.03 *	1/05-YE	4.6
11/3/05	Piedmont Natural Gas (NC)	9.04	---	---	12/04	22.4 (B)
11/30/05	Bay State Gas (MA)	8.22	10.00	53.95	12/04-YE	11.1
12/9/05	Arkansas Oklahoma Gas (AR)	6.61	9.70	41.04 *(E)	8/04-YE	4.4
12/12/05	Madison Gas and Electric (WI)	8.88 (G)	11.00	56.65	12/06-A/P	3.8
12/16/05	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/06	1.0
12/16/05	San Diego Gas & Electric (CA)	8.23	10.70	49.00	12/06	0.0
12/21/05	Baltimore Gas & Electric (MD)	8.49	11.00	48.40	7/05-A	35.6
12/21/05	Avista (WA)	9.11	10.40	40.00	12/04-A	1.0 (B)
12/22/05	Union Light, Heat and Power (KY)	8.10 (G)	10.20	54.45	9/06-A	8.1
12/22/05	Wisconsin Public Service (WI)	8.82 (G)	11.00	59.73	12/06-A/P	7.2
12/28/05	Southern Connecticut Gas (CT)	8.85	10.00	51.28	12/04-YE	26.7 (B)
2005	***4TH QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.33** **15**	**10.40** **14**	**49.03** **14**		**232.8** **17**
2005	***FULL-YEAR AVERAGES/TOTAL OBSERVATIONS***	**8.25** **29**	**10.46** **26**	**48.66** **24**		**458.4** **34**

GAS UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/5/06	Northern States Power (WI)	8.94 (G)	11.00	53.66	12/06-A	3.9
1/25/06	Wisconsin Electric Power (WI)	8.52 (G)	11.20	56.34	12/06-A	21.4
1/25/06	Wisconsin Gas (WI)	8.29 (G)	11.20	50.20	12/06-A/P	38.7
2/3/06	Public Service of Colorado (CO)	8.70	10.50	55.49	12/04-A	22.5 (B)
2/23/06	Southwest Gas (AZ)	8.40	9.50	40.00 (Hy)	8/04-YE	49.3
3/1/06	Aquila (IA)	8.88	10.40 (E)	51.39	12/04-A	2.9 (I,B)
2006	***1ST QUARTER: AVERAGES/TOTAL***	**8.62**	**10.63**	**51.18**		**138.7**
	MEDIAN	**8.61**	**10.75**	**52.53**		---
	OBSERVATIONS	**6**	**6**	**6**		**6**
4/26/06	Sierra Pacific Power (NV)	7.98	10.60	40.76	5/05-YE	4.9
5/25/06	Atmos Energy (LA)	---	10.40	48.00 (Hy)	---	--- (B)
5/26/06	Questar Gas (UT)	---	---	---	---	-9.7 (B)
2006	***2ND QUARTER: AVERAGES/TOTAL***	**7.98**	**10.50**	**44.38**		**-4.8**
	MEDIAN	**7.98**	**10.50**	**44.38**		---
	OBSERVATIONS	**1**	**2**	**2**		**2**
7/24/06	Central Hudson Gas & Electric (NY)	7.05 (6)	9.60	45.00	3/06-A	14.1 (B,Z,Di)
7/24/06	Virginia Natural Gas (VA)	---	---	---	3/05-A	0.0 (B,12)
9/20/06	Kinder Morgan (WY)	8.36	11.00	43.56	6/05-YE	6.5 (B,13)
9/26/06	Chesapeake Utilities (MD)	9.03	10.75	53.00	12/05	0.8 (B)
9/27/06	South Carolina Electric and Gas (SC)	---	---	---	3/06	17.4
2006	***3RD QUARTER: AVERAGES/TOTAL***	**8.15**	**10.45**	**47.19**		**38.8**
	MEDIAN	**8.36**	**10.75**	**45.00**		---
	OBSERVATIONS	**3**	**3**	**3**		**5**
10/20/06	Orange & Rockland Utilities (NY)	7.99	9.80	48.00	10/07-A	14.8 (B,Z,Di)
10/23/06	Public Service Co. of North Carolina (NC)	8.90	---	---	12/05-YE	15.2 (B)
10/27/06	Entergy New Orleans (LA)	---	---	---	---	9.6 (B,Z)
11/02/06	CenterPoint Energy Minnesota Gas (MN)	7.54	9.71	46.14	12/06-A	21.0 (I)
11/09/06	Public Service Electric & Gas (NJ)	7.96	10.00	47.40	9/05-YE	40.0 (B,7)
11/16/06	Kansas Gas Service (KS)	---	---	---	---	52.0 (B)
11/21/06	Consumers Energy (MI)	6.69	11.00	35.06 *	12/06-A	80.8 (I)
11/30/06	UGI Penn Natural Gas (PA)	---	---	---	12/06	12.5 (B)
12/4/06	National Fuel Gas Distribution (PA)	---	---	---	12/05	14.3 (B)
12/27/06	Kinder Morgan (NE)	---	---	---	---	8.3 (I,B)
12/28/06	Columbia Gas of Virginia (VA)	---	---	---	9/06-A	0.0 (B,14)
2006	***4TH QUARTER: AVERAGES/TOTAL***	**7.82**	**10.13**	**44.15**		**268.5**
	MEDIAN	**7.96**	**9.90**	**46.77**		---
	OBSERVATIONS	**5**	**4**	**4**		**11**
2006	***FULL YEAR: AVERAGES/TOTAL***	**8.22**	**10.44**	**47.60**		**441.2**
	MEDIAN	**8.36**	**10.50**	**48.00**		---
	OBSERVATIONS	**15**	**15**	**15**		**24**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necssarily precedent-setting or specifically adopted by the regulatory body.
Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
Di- Rate change applicable to electric distribution or gas delivery rates only.
E- Estimated
G- Return on capital
Gn- Return applicable to generation assets only.
Hy- Hypothetical capital structure utilized
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
P- Partial inclusion of CWIP in rate base without AFUDC offset to income
PBR- Performance Based Ratemaking
R- Revised
TD- Rate change applicable to electric transmission and distribution rates only.
Tr- Rate change applicable to electric transmission rates only.
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Indicated distribution rate increase to be effective 5/1/06.
(2) The electric rate increase was not supported by a traditional cost-of-service analysis, but reflected recovery of certain specific costs.
(3) Indicated rate increase to be phased-in over four years, with a 6.88% ROR authorized for 2006, 6.89% for 2007, 7.09% for 2008, and 7.48% for 2009.
(4) ROE applies only to a proposed 545-mW wind generation project.
(5) Increase is net of a $139.6 million one-time reduction resulting from a post-retirement-benefits-other-than-pensions overcollection. Additional increases of $73.5 million and $104.1 million authorized for 2007 and 2008, respectively.
(6) Multi-year rate increase adopted. Authorized ROR for year one is 7.05%, for year two is 7.09%, and for year three is 7.13%.
(7) Rate increase became effective 1/1/07.
(8) Rate increase declined to $114.9 million effective 1/1/07.
(9) Rate increase to become effective 1/1/08.
(10) The stipulation requires the company to freeze rates for five years, and over this time period, to credit its pipeline replacement program a total of $25 million and senior citizen rates $7.5 million.
(11) Indicated rate increase does not include $19.5 million of revenue previously collected through the purchased gas adjustment clause.
(12) Commission adopted a stipulated PBR plan, with no earnings restrictions. Absent PBR plan, PSC indicated that it would have ordered a $9.8 million decrease premised upon a 10% ROE (44.96% of capital) and a 7.83% ROR.
(13) While the rate increase was voted 9/20/06 and became effective 10/1/06, a final order was not issued until 12/4/06.
(14) Commission adopted a stipulated PBR plan under which 75% of earnings above a 10.5% ROE flow to ratepayers.

Dennis Sperduto

EXHIBIT
ALL-STATE LEGAL®
S-35
admitted

Tucson Electric Power
The Energy People

UNS GAS, INC.'S RESPONSES TO STAFF'S TWENTY-SECOND FIRST SET OF DATA RQUESTS DOCKET NO. G-04204A-06-0463 APRIL 2, 2007

DATE: March 26, 2007

FROM: Collin Walburn

TO: Steve Sims, Carl Dabelstein

RE: 22-2

Request

H. Provide the Company's procedures for computing AFUDC on CWIP.

Request reply

Once the AFUDC rate has been calculated according to FERC Order No. 561, the annualized rate is input into Oracle Projects and calculated as indicated below:

- A project has to be identified as "capital" within the system.
- Eligible costs are grouped into 3 unique buckets:
  - Current Month Expenditures
  - Inception-to-Date Expenditures
  - Placed-In-Service Expenditures (Current Month)
- Actual calculations:
  - Current Month Expenditures
    ((((Total Current Period Burden Costs/2)* (Rate/100))*(Days in Month/365))
  - Inception-to-Date Expenditures
    (((Total Burden Cost Prior to period start date*(Rate/100))*(Days in Month/365))
  - Place-in-service expenditures
    (((Total Burden Cost prior to Period End Date)*(Rate/100))*(Date Placed in Serice+1)-Period Start Date/365))

EXHIBIT
S-36
~~S-35~~
admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	)	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	)	DOCKET NO. G-04204A-05-0831

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

ON BEHALF OF THE COMMISSION STAFF

FEBRUARY 9, 2007

TABLE OF CONTENTS

BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. G-04204A-06-0463

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE SUMMARIZE YOUR EDUCATION BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in over 375 utility proceedings before about 35 regulatory agencies in the United States and Canada. Schedule 1 provides a more complete description of my education and relevant work experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent electric rate case involving Arizona Public Service Company (Docket No. E-01345A-05-0816). That testimony was provided on behalf of the Commission Staff.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Commission Staff to evaluate the cost of capital aspects of the current filing of UNS Gas, Inc. ("UNS Gas"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Gas. In addition, because UNS Gas is a subsidiary of UniSource Energy Corporation ("UniSource Energy"), I also have evaluated this entity in my analyses.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendations for UNS Gas are:

	Percent	Cost	Return
Long-Term Debt	55.33%	6.60%	3.65%
Common Equity	44.67%	9.50-10.50%	4.24-4.69%
Total	100.00%		7.89-8.34%
			8.12% mid-point

UNS Gas' application requests a return on common equity of 11.0 percent and overall rate of return of 8.80 percent.

Q. PLEASE SUMMARIZE YOUR COST OF CAPITAL ANALYSES AND RELATED CONCLUSIONS FOR UNS GAS.

A. This proceeding is concerned with UNS Gas' regulated natural gas distribution utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. UNS Gas' proposed capital structure is a hypothetical capital structure that employs 50 percent long-term debt and 50 percent common equity. I use the actual capital structure of UNS Gas as of December 31, 2005 in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the 6.60 percent cost rate for long-term debt contained in UNS Gas' application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Gas. Each of these methodologies is applied to two groups: one of proxy gas utilities and one of a combination of gas and electric utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.25-10.5% (9.88% mid-point)
Capital Asset Pricing Model	9.5-10.25% (9.88% mid-point)
Comparable Earnings	10.0%

Based upon these findings, I conclude that the cost of common equity for UNS Gas is within a range of 9.5 percent to 10.5 percent (10 percent mid-point), which reflects each of the model results.

Using the results from these three steps, I have calculated a weighted cost of capital (overall rate of return) range of 7.89 percent to 8.34 percent (8.12 percent mid-point, which incorporates a cost of common equity of 10.0 percent). My specific cost of capital recommendation for UNS Gas is 8.12 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return and allowing a factor for income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments.

These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity

> **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In *Simms v. Round Valley Light & Power Company*,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the Court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of UNS Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the *Hope* and *Bluefield*

[1] 294 P.2d 378 (1956).

decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the component of the capital structure that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. I have utilized three methodologies to determine UNS Gas' cost of common equity: the DCF, CAPM, and CE methods. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. WHY ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN DETERMINING THE COSTS OF CAPITAL?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of the factors is consistent with the Supreme Court's Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE CHANGING TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT ON COSTS OVER THIS BROAD PERIOD?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession in 2001. During the recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Fed Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while Pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that the U.S. economy is currently in the fifth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on Page 1 of Schedule 2. As is reflected in the Consumer Price Index (CPI), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.4 percent rate of inflation in 2005, which was similar to the level for 2004, was slightly higher than the most recent years, but was well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on 17 occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. In fact, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000. Even if rates were to increase moderately, they would still remain well below historical levels.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high levels.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, currently produce returns that are lower than was the case in prior years.

V. UNS GAS' OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE UNS GAS AND ITS OPERATIONS.

A. UNS Gas is a public utility that provides natural gas distribution services to some 140,000 customers in Arizona. UNS Gas was formerly the Arizona local gas distribution operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Gas and UNS Electric.

Q. PLEASE DESCRIBE UNISOURCE ENERGY.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which contains UNS Gas and UNS Electric, both of which are distribution companies. It also owns Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary is Global Solar. UniSource Energy operates through four primary business segments – TEP, UNS Gas, UNS Electric, and Global Solar (the 2005 Annual Report of UniSource Energy indicated that the Company is in the process of exiting its Millennium Energy investments).

Q. WHAT HAVE BEEN THE BUSINESS SEGMENT RATIOS OF UNISOURCE ENERGY IN RECENT YEARS?

A. This is shown on Schedule 3. As this indicates, as of 2005, UNS Gas accounted for about 11 percent of the revenues of UniSource Energy and about 7 percent of total assets.

Q. WHAT ARE THE CURRENT BOND RATINGS OF UNISOURCE ENERGY AND TEP?

A. The current ratings of UniSource Energy and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB-	Baa2	BBB-
Senior Unsecured Debt	B+	Baa3	BB+
Issuer Rating	BB	Baa3	BB

Source: UniSource Energy Web Site.

UNS Gas does not have its own security ratings. The debt of UNS Gas is guaranteed by UES. As such, the debt of UNS Gas is related to the overall credit strength of UniSource Energy and TEP.

Q. DID THE ACQUISITION OF THE ASSETS CURRENT COMPRISING UNS GAS HAVE ANY IMPACT ON THE SECURITY RATINGS OF UNISOURCE ENERGY OR TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and gas **transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.
>
> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support,

> mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. UNS GAS IS PROPOSING A DECOUPLING MECHANISM. DOES THE POTENTIAL APPROVAL OF THIS REGULATORY MECHANISM AFFECT UNS GAS' RISK?

A. Yes, it does. Staff Witness Smith addresses UNS Gas' proposed mechanism in detail and generally concludes that the proposed regulatory mechanism is risk-reducing to the company as it transfers a portion of the risk from shareholders to ratepayers.

Q. HAS STANDARD & POOR'S COMMENTED GENERALLY ON THE POSITIVE ATTRIBUTES OF REGULATORY COST-RECOVERY MECHANISMS?

A. Yes, it has. In a 2006 Commentary Report, titled "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," S&P made the following comments:

> … in an environment of sustained elevated natural gas prices, will regulators continue to allow the LDCs the proper tools to capture costs and maintain credit quality? The answer to this question will be key in LDCs maintaining their credit quality as, historically, companies with stable recovery mechanisms have maintained strong ratings.
>
> . . .
>
> Regulatory Mechanisms
> Most LDCs operate in jurisdictions where regulators provide a purchased-gas adjustment clause, which reduces a significant portion of the risk associated with operating with volatile gas price costs.
>
> . . .
>
> Given today's high and volatile natural gas prices, maintaining strong credit quality depends on ratepayers bearing the responsibility for commodity costs. Automatic pass-through mechanisms linked to gas price indices provide the strongest level of support.

Several points are apparent from this report. First and significantly, pass-through mechanisms have the effect of transferring a portion of an LDC's risks from its stockholders to its ratepayers. Second, it is apparent that UNS Gas' proposed cost-recovery mechanism reduces risk by decoupling revenue from consumption. Third, the proposed additional regulatory mechanisms will have the effect, if approved, of further reducing UNS Gas' risk.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE NEW REGULATORY MECHANISM THAT UNS GAS IS PROPOSING IN THIS PROCEEDING.

A. The decoupling mechanism is intended to insulate the Company from any variation in distribution revenues attributed to conservation, weather effects or price responses by the customer. This mechanism is especially risk-reducing.

Q. WHAT WILL BE THE EFFECT ON UNS GAS' PERCEIVED RISKS IF THESE REGULATORY MECHANISMS ARE ADOPTED?

A. The effect will be to transfer a significant portion of UNS Gas' business risks from its stockholders to its ratepayers.

Q. ARE YOU AWARE THAT UNS GAS IS REQUESTING THE INCLUSION OF CONSTRUCTION WORK IN PROCESS AS PART OF ITS RATE FILING?

A. Yes, I am. It is my understanding that UNS Gas is requesting some $7.2 million of Construction Work In Progress ("CWIP") in its request, which results in about $1.5 million of annual revenues to the Company. UNS Gas witness Grant cites the inclusion of CWIP as necessary for the Company to attract capital.

Q. DO YOU AGREE THAT IT IS NECESSARY FOR UNS GAS TO HAVE CWIP TREATMENT IN ORDER FOR IT TO ATTRACT CAPITAL?

A. No, I do not. It has been my general experience that CWIP treatment is generally regarded as a ratemaking practice to be used in situations where a utility has a very large construction program and the company requires the cash treatment in order to manage its construction program and related financing. As such, CWIP is not the norm, particularly for gas distribution companies.

In the case of UNS Gas, I do not believe that it is necessary to provide CWIP treatment in order for this Company to attract capital. As I indicated above, the rating agencies describe the operations of UNS Gas as low risk. It is further apparent that UNS Gas receives its financing based on the credit quality of UniSource Energy and/or UES, not based on the situation of the Company itself. In summary, I do not believe it is necessary for UNS Gas to receive CWIP treatment in order for it to attract capital.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULATORY FRAMEWORK?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the pool of dollars represented by the capital structure finance the rate base.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW IS UNS GAS FINANCED?

A. UNS Gas is a subsidiary of UES, which in turn is a subsidiary of UniSource Energy. UNS Gas has two series of long-term notes outstanding, both of which are guaranteed by UES.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF UNS GAS AND UNISOURCE ENERGY?

A. I have first examined the recent capital structure ratios of UNS Gas and UniSource Energy.

UNS Gas' capital structure did not exist until 2003, when UniSource Energy created a subsidiary from the local gas distribution assets in Arizona, as acquired from Citizens Communications. As is shown on Page 1 of Schedule 4, the common equity ratios of UNS Gas have been as follows:

	Including S-T Debt	Excluding S-T Debt
2003	34.7%	34.7%
2004	37.0%	37.0%
2005	44.4%	44.4%

This indicates a rising level of common equity over this period.

Q. WHAT ARE THE CAPITAL STRUCTURE RATIOS OF UNISOURCE ENERGY?

A. These are shown on Page 2 of Schedule 4. These common equity ratios of UniSource Energy, on a consolidated basis, are summarized below:

	Including S-T Debt	Excluding S-T Debt
2001	28.0%	28.0%
2002	28.8%	28.8%
2003	30.2%	30.2%
2004	31.6%	31.6%
2005	33.5%	33.6%

These common equity ratios are somewhat less than those of UNS Gas.

Q. HOW DO THE CAPITAL STRUCTURES OF UNS GAS COMPARE TO THE OTHER UTILITY SUBSIDIARIES OF UNISOURCE ENERGY?

A. This is shown on Page 3 of Schedule 4. As this indicates, UNS Gas and UNS Electric have higher common equity ratios than TEP and UniSource Energy.

Q. HOW DO THESE CAPITAL STRUCTURES COMPARE TO THOSE OF INVESTOR-OWNED ELECTRIC AND COMBINATION GAS/ELECTRIC UTILITIES?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

These common equity ratios are generally similar to those of UNS Gas in 2005.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS UNS GAS REQUESTED IN THIS PROCEEDING?

A. The Company requests use of a hypothetical capital structure, comprised of 50 percent common equity and 50 percent long-term debt.

Q. DO YOU AGREE THAT THIS IS THE PROPER CAPITAL STRUCTURE TO USE FOR UNS GAS?

A. No, I do not. This capital structure contains a percentage of common equity that exceeds the historic levels of common equity employed by UNS Gas, as well as the other utility subsidiaries of UniSource Energy. It should be noted that use of a hypothetical structure, such as that proposed by UNS Gas, would have the effect, if adopted, of increasing the actual return on equity to a level exceeding that intentionally approved by the Commission. For example, if the cost of capital, including the capital structure, requested by UNS Gas were to be approved, the following cost of capital would be reflected in rates:

	Percent	Cost	Wgt. Cost
Debt	50%	6.6%	3.65%
Equity	50%	11.0%	5.15%
Totals			8.80%

It is apparent, however, that an awarded return of 8.8 percent would produce a higher actual return on equity, as shown below:

	Percent	Cost	Wgt. Cost
Debt	55.33%	6.6%	3.65%
Equity	44.67%	11.5%	5.15%
Totals			8.80%

This demonstrates that use of a hypothetical capital structure, as proposed by UNS Gas, would have the impact on increasing the actual return on equity by 50 basis points, or 0.50 percent.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I propose use of the actual capital structure ratios of UNS Gas. This capital structure reflects the per books ratios of the Company.

Q. WHAT IS THE COST RATE OF LONG-TERM DEBT IN THE COMPANY'S APPLICATION?

A. The Company's filing cites a cost of long-term debt of 6.60 percent. I use this rate in my cost of capital analyses.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COST OF DEBT?

A. No. The cost rate of debt is largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR UNS GAS?

A. UNS Gas is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to this entity. Its ultimate parent company, UniSource Energy, is publicly-traded. As a result, it is possible to conduct direct analyses of its cost of common equity, although this company's recent financial situation and diversified nature make its results of limited value. Consequently, it is necessary to analyze groups of comparison or "proxy" companies as a substitute for UNS Gas to determine its cost of common equity.

I have examined two such groups for comparison to UNS Gas. The first group of proxy companies I examined is a group of nine electric and combination gas electric companies, similar to UniSource Energy, selected based on the criteria shown on my Schedule 6. Second is the group of eleven natural gas utilities used by UNS Gas witness Grant in his cost of capital analyses.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)
P = current price
D = current dividend rate
G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a dividend growth variant, which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (October-December 2006). The D_0 is the current annualized dividend rate for each proxy company.

Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF THE DCF EQUATION?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2001-2005 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);
3. 2006, 2007, and 2009-2011 projections of earnings retention growth (per Value Line);
4. 2003-2005 to 2009-2011 projections of EPS, DPS, and BVPS (per Value Line); and,
5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. PLEASE DESCRIBE YOUR INITIAL DCF CALCULATIONS.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and range of low/high values. These results can be summarized as follows:

	Mean	Median	High[2]
Comparison Group	8.3%	8.3%	10.5%
Grant Group	8.0%	7.4%	9.2%

[2] Using only the highest growth rate.

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

The DCF results in Schedule 7 indicate average (mean and median) DCF cost rates of about 7.5 percent to 8.5 percent. The highest DCF rates (i.e., using the highest growth rates only) are about 9.25 percent to 10.5 percent.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a broad range of 9.25 percent to 10.5 percent represents the current DCF cost of equity for the proxy groups. This is approximated by the top DCF calculations for the groups examined in the previous analysis. I recommend a 9.25 percent to 10.5 percent (9.88 percent mid-point) for UNS Gas, which focuses on the upper portion of the DCF range.

I have focused on the upper portion of the DCF calculations since current financial conditions (low interest rates and high market-to-book ratios for utilities) have the effect of driving DCF results to low levels by historic standards.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model ("CAPM") is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

β = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method does not, but rather the simple risk premium method assumes the same cost of equity for all companies exhibiting similar bond ratings.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three month average yield (October-December 2006) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.84 percent.

Q. WHAT IS BETA AND WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?

A. The market risk premium component (R_m-R_f) represents the *investor-expected* premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2005 period is 14.09 percent. This Schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S.

Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.5%	4.9%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Comparison Group	10.3%	10.3%
Grant Group	9.9%	9.6%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY?

A. The CAPM results collectively indicate a cost of about 9.5 percent to 10.25 percent for the two groups of comparison utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's original book value (reflected in the book common equity in its balance sheet) to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF UNS GAS' COMMON EQUITY COST?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution of book value. As a result, maintenance of a stock price above book value is one measure of the fairness of a utility's authorized cost of equity.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not backward looking.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2005 (i.e., last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2001-2005 (the last five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Comaprison Group	10.7%	171-197%	10.0-11.2%
Grant Group	11.6-11.8%	178-181%	10.3-11.7%

These results indicate that historic returns of 10.7-11.8 percent have been adequate to produce market-to-book ratios of 171-197 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2006, 2007, and 2009-2011 are within a range of 10.0 percent to 11.7 percent for the utility groups. These relate to 2005 market-to-book ratios of 192 percent or higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past fourteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.2 to 14.7 percent with market-to-book ratios ranging from 299 to 341 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR UNS GAS?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industries with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is slightly more risky than the utility proxy groups.

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 10 percent. Recent returns of 10.7 to 11.8 percent have resulting in market-to-book ratios of 171 and greater.

Prospective returns of 10.0 to 11.7 percent have been accompanied by market-to-book ratios of over 197 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

XI. RETURN ON EQUITY RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies produce the following:

Discounted Cash Flow	9.25-10.5% (9.88% mid-point)
Capital Asset Pricing Model	9.5-10.25% (9.88% mid-point)
Comparable Earnings	10.0%

My overall conclusion from these results is an overall range of 9.25 percent to 10.5 percent, which focuses on the respective ranges of my individual model findings. Focusing on the respective mid-points, the range is 9.88 percent to 10.0 percent. I conclude that the cost of equity rate for UNS Gas is in the range from 9.5 percent to 10.5 percent (mid-point 10.0 percent).

XII. TOTAL COST OF CAPITAL

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR UNS GAS?

A. Schedule 13 reflects the total cost of capital for the Company using the December 31, 2005 capital structure and cost of long-term debt, and my common equity cost recommendations. The resulting total cost of capital is a range of 7.89 percent to 8.34 percent, with a mid-point of 8.12 percent. I recommend that this 8.12 total cost of capital be established for UNS Gas.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Gas earned the mid-point of my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level within the benchmark range for a BBB rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. HAVE YOU REVIEWED THE TESTIMONY AND COST OF CAPITAL RECOMMENDATION OF UNS GAS WITNESS KENTTON C. GRANT?

A. Yes, I have. Mr. Grant is recommending the following cost of capital for UNS Gas:

Capital Item	Percent	Cost	Weighted Cost
Long-term Debt	50.0%	6.60%	3.30%
Common Equity	50.0%	11.00%	5.50%
Total	100.0%		8.80%

Mr. Grant's 11.0 percent cost of common equity recommendation is derived as follows:

	Range	Median
DCF	9.1-10.5%	9.9%
CAPM	9.9-11.7%	11.0%

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. GRANT'S DCF ANALYSIS AND RECOMMENDATIONS?

A. I note that Mr. Grant's 9.1-10.5 percent DCF conclusions do not very significantly from my DCF conclusions of 9.25-10.5 percent. As a result, I have no further comments on his DCF analyses and conclusions at this time.

Q. WHAT ARE YOUR COMMENTS CONCERNING MR. GRANT'S CAPM ANALYSIS AND CONCLUSIONS?

A. Mr. Grant's CAPM analysis takes the following form:

Risk-free rate	=	5.3%	=	April, 2006 20-yr. T bonds
Risk Premium	=	5.3%	=	Ibbotson risk premium
Beta	=		=	Value Line

I have concerns with Mr. Grant's risk-free rate and his risk premium inputs. His 5.3 percent risk free rate is now out-dated. As I indicated in my CAPM analyses, the current (i.e., December, 2006) yield on 20-year Treasury bonds is 4.78 percent and the most recent three-month average (i.e., October-December, 2006) yield is 4.83 percent.

My disagreement with Mr. Grant's risk premium is his exclusive reliance on the 1926-2005 arithmetic average difference between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done.

Q. MR. GRANT ALSO MAKES AN ADJUSTMENT FOR THE SIZE OF UNS GAS. IS THIS PROPER?

A. No, it is not. UNS Gas does not raise its own equity capital (as it comes from UniSource Energy) and its debt is guaranteed by UES. As a result, it is these entities that are evaluated by investors and it is the size of these entities that investors consider. I note, in this regard, that UniSource Energy has some $1.3 billion market value of equity and Value Line describes this Company as a "Mid Cap" stock.

Q. MR. GRANT ALSO CITES THE GROWTH OF UNS GAS AS A RISK INDICATOR. DO YOU AGREE WITH THIS?

A. No, I do not. My earlier testimony cites a S&P analysis of UniSource Energy that describes the UNS Gas and UNS Energy components as "low-risk."

Q. DO YOU AGREE WITH MR. GRANT'S PROPOSED HYPOTHETICAL CAPITAL STRUCTURE?

A. No, I do not. As I indicated earlier, it is not proper to impute more equity to UNS Gas than it and/or its parent affiliate companies employ.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

<u>Utility Economics</u> -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.8%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.6%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	-0.3%	5.8%	2.4%	1.2%
2003	2.7%	0.0%	6.0%	1.9%	4.0%
2004	4.2%	4.2%	5.5%	3.3%	4.1%
2005					
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.7%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.7%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.2%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	3.6%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.					
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	1.6%	5.2%	4.7%	0.4%	-4.4%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005							
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec					5.62%	5.81%	6.05%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005					
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.88%
3rd Qtr.	1,288.40	2,141.97		1.91%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

UNISOURCE ENERGY
SEGMENT FINANCIAL INFORMATION
2003 - 2005
($millions)

Segment	Operating Revenue	Net Income	Total Assets
		2003	
Tucson Electric Power	$852 87.6%	$129 113.2%	$2,767 88.6%
UNS Gas 1/	$47 4.8%	$1 0.9%	$185 5.9%
UNS Electric 1/	$56 5.8%	$2 1.8%	$125 4.0%
Global Solar	$2 0.2%	-$7 -6.1%	$26 0.8%
UniSource Energy Consolidated	$973	$114	$3,123
		2004	
Tucson Electric Power	$889 76.0%	$46 100.0%	$2,742 86.3%
UNS Gas	$129 11.0%	$6 13.0%	$201 6.3%
UNS Electric	$144 12.3%	$4 8.7%	$135 4.3%
Global Solar	$5 0.4%	-$5 -10.9%	$20 0.6%
UniSource Energy Consolidated	$1,169	$46	$3,176
		2005	
Tucson Electric Power	$937 76.2%	$48 104.3%	$2,575 82.3%
UNS Gas	$138 11.2%	$5 10.9%	$233 7.5%
UNS Electric	$150 12.2%	$5 10.9%	$161 5.1%
Global Solar	$5 0.4%	-$7 -15.2%	$20 0.6%
UniSource Energy Consolidated	$1,230	$46	$3,127

1/ 2003 figures for UNS Gas and UNS Electric are for period August 11 through December 31.

Note: Totals may not add to 100.0% due to "All Others" and "Reconciling Adjustments."

Source: UniSource Energy Annual Report.

UNS GAS
CAPITAL STRUCTURE RATIOS
2003 - 2005
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$53,085	$0	$100,000	$0
	34.7%	0.0%	65.3%	0.0%
	34.7%	0.0%	65.3%	
2004	$58,758	$0	$100,000	$0
	37.0%	0.0%	63.0%	0.0%
	37.0%	0.0%	63.0%	
2005	$79,804	$0	$100,000	$0
	44.4%	0.0%	55.6%	0.0%
	44.4%	0.0%	55.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 7.4.

UNISOURCE ENERGY CONSOLIDATED
CAPITAL STRUCTURE RATIOS
2001 - 2005
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2001	$441,133.0	$0.0	$1,133,228.0	$0.0
	28.0%	0.0%	72.0%	0.0%
	28.0%	0.0%	72.0%	
2002	$456,640.0	$0.0	$1,130,803.0	$0.0
	28.8%	0.0%	71.2%	0.0%
	28.8%	0.0%	71.2%	
2003	$556,472.0	$0.0	$1,288,062.0	$0.0
	30.2%	0.0%	69.8%	0.0%
	30.2%	0.0%	69.8%	
2004	$580,718.0	$0.0	$1,259,320.0	$0.0
	31.6%	0.0%	68.4%	0.0%
	31.6%	0.0%	68.4%	
2005	$616,741.0	$0.0	$1,217,420.0	$5,000.0
	33.5%	0.0%	66.2%	0.3%
	33.6%	0.0%	66.4%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 7.4.

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
December 31, 2005
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource Energy	$616,741.0	$0.0	$1,217,420.0	$5,000.0
Consolidated	33.5%	0.0%	66.2%	0.3%
	33.6%	0.0%	66.4%	
Tucson Electric	$558,646.0	$0.0	$821,170.0	$0.0
Power Company	40.5%	0.0%	59.5%	0.0%
	40.5%	0.0%	59.5%	
UNS Electric	$49,868.0	$0.0	$60,000.0	$5.0
	45.4%	0.0%	54.6%	0.0%
	45.4%	0.0%	54.6%	
UNS GAS	$79,804.0	$0.0	$100,000.0	$0.0
	44.4%	0.0%	55.6%	0.0%
	44.4%	0.0%	55.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 7.4.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
Unisource Energy	$1,300,000	86%	25%	3	BBB- / Baa2	B
Comparison Group*						
Cleco	$1,300,000	96%	52%	3	BBB / Baa1	B+
DPL Inc	$3,100,000	100%	38%	3	BBB /	B+
Duquesne Light Holdings	$1,500,000	79%	37%	4	BBB+ / Baa1	B
Empire District	$675,000	93%	49%	3	BBB+ / Baa1	B
Hawaiian Electric	$2,300,000	83%	53%	2	BBB / Baa2	B+
Northeast Utilities	$3,500,000	71%	35%	3	BBB / Baa1	B
Pepco Holdings	$4,600,000	79%	42%	3	BBB+ / Baa1	B
PNM Resources	$2,000,000	78%	42%	2	BBB / Baa2	B+
Puget Energy	$2,800,000	61%	46%	3	BBB / Baa2	B

* Selected using following criteria:
Market cap of $500 million to $5 billion.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% or greater.
Value Line Safety of 1, 2 or 3.
S&P bond ratings of BBB and Moody's bond ratings of Baa.
S&P stock ranking of B or B+.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	October-December, 2006 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Cleco	$0.90	$26.20	$24.78	$25.49	3.5%
DPL Inc	$1.00	$28.20	$27.00	$27.60	3.6%
Duquesne Light Holdings	$1.00	$20.28	$19.49	$19.89	5.0%
Empire District	$1.28	$25.10	$21.61	$23.36	5.5%
Hawaiian Electric	$1.24	$28.18	$26.50	$27.34	4.5%
Northeast Utilities	$0.75	$28.90	$23.26	$26.08	2.9%
Pepco Holdings	$1.04	$26.99	$24.25	$25.62	4.1%
PNM Resources	$0.88	$32.07	$27.47	$29.77	3.0%
Puget Energy	$1.00	$25.91	$22.72	$24.32	4.1%
Average	$1.01	$26.87	$24.12	$25.50	**4.0%**
Grant Comparable Gas Group					
AGL Resources	$1.48	$40.09	$36.04	$38.07	3.9%
Atmos Energy Corp	$1.28	$33.09	$28.40	$30.75	4.2%
Cascade Natural Gas	$0.96	$26.17	$25.40	$25.79	3.7%
Laclede Gas Company	$1.46	$37.51	$31.60	$34.56	4.2%
New Jersey Resources	$1.52	$53.16	$48.46	$50.81	3.0%
Nicor, Inc	$1.86	$49.92	$42.38	$46.15	4.0%
Northwest Natural Gas	$1.42	$43.69	$38.53	$41.11	3.5%
Piedmont Natural Gas	$0.96	$28.44	$24.95	$26.70	3.6%
South Jersey Industries	$0.98	$34.26	$29.10	$31.68	3.1%
Southwest Gas	$0.82	$39.37	$32.80	$36.09	2.3%
WGL Holdings	$1.35	$33.55	$31.16	$32.36	4.2%
Average	$1.28	$38.11	$33.53	$35.82	**3.6%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	2009-2011	Average
Comparison Group										
Cleco	6.5%	5.6%	3.5%	3.9%	4.1%	4.7%	2.5%	3.0%	4.0%	3.2%
DPL Inc	13.7%	0.0%	2.2%	9.8%	0.8%	5.3%	8.0%	10.0%	6.5%	8.2%
Duquesne Light Holdings	0.0%	1.5%	2.5%	5.4%	4.5%	2.8%	0.0%	2.0%	4.5%	2.2%
Empire District	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	1.0%	3.0%	1.3%
Hawaiian Electric	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.5%	2.3%
Northeast Utilities	5.6%	3.2%	3.7%	1.6%	1.5%	3.1%	5.0%	4.0%	4.0%	4.3%
Pepco Holdings	12.6%	5.3%	2.0%	2.5%	2.4%	5.0%	1.5%	3.0%	5.0%	3.2%
PNM Resources	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Puget Energy	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.0%	3.0%	3.5%	2.8%
Average	6.1%	2.7%	2.6%	3.5%	2.4%	**3.5%**	2.7%	3.6%	4.2%	**3.5%**
Grant Comparable Gas Group										
AGL Resources	4.2%	7.0%	6.6%	5.6%	6.2%	5.9%	5.5%	5.5%	5.0%	5.3%
Atmos Energy Corp	2.1%	1.9%	2.8%	1.7%	2.3%	2.2%	2.2%	3.0%	3.0%	2.7%
Cascade Natural Gas	4.6%	1.7%	0.0%	2.1%	0.0%	1.7%	1.0%	1.5%	4.5%	2.3%
Laclede Gas Company	1.8%	0.0%	3.1%	2.7%	3.1%	2.1%	2.1%	4.0%	3.5%	3.2%
New Jersey Resources	6.1%	6.9%	7.7%	7.8%	8.5%	7.4%	7.4%	8.0%	7.5%	7.6%
Nicor, Inc	7.9%	6.5%	1.5%	2.1%	2.3%	4.1%	4.5%	4.0%	3.5%	4.0%
Northwest Natural Gas	3.5%	1.9%	2.6%	2.7%	3.7%	2.9%	2.9%	3.7%	3.7%	3.4%
Piedmont Natural Gas	3.0%	1.7%	3.1%	3.7%	3.6%	3.0%	3.0%	3.5%	4.0%	3.5%
South Jersey Industries	3.5%	4.7%	5.0%	5.9%	6.2%	5.1%	5.1%	6.5%	6.5%	6.0%
Southwest Gas	1.9%	1.9%	1.7%	4.3%	2.2%	2.4%	2.4%	5.0%	6.0%	4.5%
WGL Holdings	3.8%	0.0%	6.2%	4.1%	4.6%	3.7%	3.7%	2.5%	3.0%	3.1%
Average	3.9%	3.1%	3.7%	3.9%	3.9%	**3.7%**	3.6%	4.3%	4.6%	**4.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '03-'05 to '09-'11 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Cleco	1.0%	2.0%	4.0%	2.3%	4.5%	2.0%	8.5%	5.0%
DPL Inc	-1.0%	0.5%	-1.0%	-0.5%	5.5%	3.5%	3.5%	4.2%
Duquesne Light Holdings	-12.0%	-8.5%	-14.5%	-11.7%	5.0%	0.0%	5.5%	3.5%
Empire District	-5.0%	0.0%	2.0%	-1.0%	9.5%	0.0%	2.5%	4.0%
Hawaiian Electric	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
Pepco Holdings	-1.0%	0.0%	0.5%	-0.2%	8.0%	3.0%	3.0%	4.7%
PNM Resources	-1.0%	5.0%	4.5%	2.8%	6.0%	8.5%	5.5%	6.7%
Puget Energy	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Average	-2.8%	2.0%	0.2%	**-0.2%**	6.1%	2.8%	4.1%	**4.3%**
Grant Comparable Gas Group								
AGL Resources	13.5%	2.0%	8.5%	8.0%	4.5%	6.5%	6.0%	5.7%
Atmos Energy Corp	6.5%	2.0%	8.5%	5.7%	7.0%	2.0%	5.0%	4.7%
Cascade Natural Gas	3.5%	0.0%	??	1.8%	7.0%	0.5%	6.0%	4.5%
Laclede Gas Company	4.5%	0.5%	2.5%	2.5%	5.0%	2.0%	7.0%	4.7%
New Jersey Resources	8.5%	3.0%	7.0%	6.2%	4.5%	4.5%	6.5%	5.2%
Nicor, Inc	-3.5%	3.5%	1.5%	0.5%	4.0%	1.0%	4.5%	3.2%
Northwest Natural Gas	5.0%	1.0%	3.5%	3.2%	7.0%	4.0%	3.5%	4.8%
Piedmont Natural Gas	5.0%	5.0%	6.0%	5.3%	6.0%	5.5%	3.0%	4.8%
South Jersey Industries	11.5%	2.5%	13.0%	9.0%	7.0%	6.0%	6.0%	6.3%
Southwest Gas	-0.5%	0.0%	3.0%	0.8%	9.0%	0.0%	4.0%	4.3%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	1.5%	2.0%	3.5%	2.3%
Average	5.5%	1.9%	5.7%	**4.2%**	5.7%	3.1%	5.0%	**4.6%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Cleco	3.6%	4.7%	3.2%	2.3%	5.0%	10.5%	5.1%	8.8%
DPL Inc	3.7%	5.3%	8.2%		4.2%	5.0%	5.7%	9.4%
Duquesne Light Holdings	5.1%	2.8%	2.2%		3.5%	n/a	2.8%	7.9%
Empire District	5.5%	0.0%	1.3%		4.0%	3.0%	2.1%	7.6%
Hawaiian Electric	4.6%	3.0%	2.3%	1.3%	1.8%	3.0%	2.3%	6.9%
Northeast Utilities	3.0%	3.1%	4.3%	11.2%	5.5%	12.0%	7.2%	10.2%
Pepco Holdings	4.1%	5.0%	3.2%		4.7%	4.0%	4.2%	8.3%
PNM Resources	3.0%	5.4%	3.8%	2.8%	6.7%	9.7%	5.7%	8.7%
Puget Energy	4.2%	1.8%	2.8%		3.5%	4.0%	3.0%	7.2%
Average	4.1%	3.5%	3.5%	4.4%	4.3%	6.4%	4.2%	**8.3%**
Median								**8.3%**
Composite		7.6%	7.6%	8.5%	8.4%	**10.5%**	8.3%	
Grant Comparable Gas Group								
AGL Resources	4.0%	5.9%	5.3%	8.0%	5.7%	n/a	6.2%	10.2%
Atmos Energy Corp	4.3%	2.2%	2.7%	5.7%	4.7%	6.1%	4.3%	8.5%
Cascade Natural Gas	3.8%	1.7%	2.3%	1.8%	4.5%	n/a	2.6%	6.3%
Laclede Gas Company	4.3%	2.1%	3.2%	2.5%	4.7%	n/a	3.1%	7.4%
New Jersey Resources	3.1%	7.4%	7.6%	6.2%	5.2%	5.0%	6.3%	9.4%
Nicor, Inc	4.1%	4.1%	4.0%	0.5%	3.2%	3.1%	3.0%	7.1%
Northwest Natural Gas	3.5%	2.9%	3.4%	3.2%	4.8%	5.0%	3.9%	7.4%
Piedmont Natural Gas	3.7%	3.0%	3.5%	5.3%	4.8%	4.0%	4.1%	7.8%
South Jersey Industries	3.2%	5.1%	6.0%	9.0%	6.3%	6.0%	6.5%	9.7%
Southwest Gas	2.3%	2.4%	4.5%	0.8%	4.3%	12.0%	4.8%	7.1%
WGL Holdings	4.2%	3.7%	3.1%	3.5%	2.3%	3.0%	3.1%	7.4%
Average	3.7%	3.7%	4.2%	4.2%	4.6%	5.5%	4.3%	**8.0%**
Median								**7.4%**
Composite		7.4%	7.8%	7.9%	8.3%	**9.2%**	8.0%	

Note: Negative values excluded.
Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.26%	5.11%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average			**14.09%**	**7.90%**	**6.19%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET RETURN	CAPM RATES
Comparison Group				
Cleco	4.83%	1.25	5.90%	12.2%
DPL Inc	4.83%	0.95	5.90%	10.4%
Duquesne Light Holdings	4.83%	1.00	5.90%	10.7%
Empire District	4.83%	0.80	5.90%	9.6%
Hawaiian Electric	4.83%	0.70	5.90%	9.0%
Northeast Utilities	4.83%	0.90	5.90%	10.1%
Pepco Holdings	4.83%	0.90	5.90%	10.1%
PNM Resources	4.83%	1.00	5.90%	10.7%
Puget Energy	4.83%	0.80	5.90%	9.6%
Average	4.83%	0.92	5.90%	**10.3%**
Median				**10.3%**
Grant Comparable Gas Group				
AGL Resources	4.83%	0.95	5.90%	10.4%
Atmos Energy Corp	4.83%	0.80	5.90%	9.6%
Cascade Natural Gas	4.83%	0.80	5.90%	9.6%
Laclede Gas Company	4.83%	0.90	5.90%	10.1%
New Jersey Resources	4.83%	0.80	5.90%	9.6%
Nicor, Inc	4.83%	1.30	5.90%	12.5%
Northwest Natural Gas	4.83%	0.75	5.90%	9.3%
Piedmont Natural Gas	4.83%	0.80	5.90%	9.6%
South Jersey Industries	4.83%	0.70	5.90%	9.0%
Southwest Gas	4.83%	0.85	5.90%	9.8%
WGL Holdings	4.83%	0.85	5.90%	9.8%
Average	4.83%	0.86	5.90%	**9.9%**
Median				**9.6%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average	2006	2007	2009-11
Comparison Group																			
Cleco	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	13.5%	12.8%	8.0%	8.5%	9.5%
DPL Inc	13.3%	14.5%	15.1%	15.2%	15.5%	15.4%	14.9%	15.2%	18.6%	25.4%	22.6%	16.1%	23.5%	12.6%	16.3%	20.0%	26.5%	26.0%	18.5%
Duquesne Light Holdings	12.4%	12.0%	12.5%	13.2%	13.2%	12.9%	13.1%	14.0%	8.0%	2.7%	16.2%	15.0%	15.6%	14.1%	11.4%	12.7%	6.0%	13.0%	13.5%
Empire District	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.3%	6.7%	7.0%	9.0%	10.5%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	11.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	6.8%	3.8%	6.8%	9.5%	8.5%	8.5%
Pepco Holdings	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	11.0%	9.1%	7.0%	8.5%	10.5%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.0%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.8%	7.5%	8.5%	8.5%
Average	11.3%	11.1%	11.8%	11.5%	10.5%	9.3%	10.6%	9.7%	10.3%	11.5%	11.4%	10.1%	10.7%	9.6%	**10.7%**	**10.7%**	**10.0%**	**11.2%**	**10.9%**
Composite															**10.8%**	**10.7%**			
Grant Comparable Gas Group																			
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	11.8%	14.0%	13.0%	12.5%	12.0%
Atmos Energy Corp	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	11.4%	10.2%	10.0%	9.5%	11.0%
Cascade Natural Gas	7.1%	11.0%	6.1%	8.2%	9.6%	9.2%	8.3%	12.1%	13.1%	13.5%	10.6%	8.5%	11.5%	7.8%	9.8%	10.4%	10.0%	1.5%	11.0%
Laclede Gas Company	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	11.3%	10.5%	12.5%	10.5%	9.5%
New Jersey Resources	12.1%	11.9%	13.0%	13.3%	13.8%	14.5%	14.6%	14.9%	15.1%	15.2%	15.9%	16.7%	15.8%	16.2%	13.8%	16.0%	12.6%	12.5%	12.0%
Nicor, Inc	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	16.2%	14.9%	14.0%	13.0%	12.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.5%	9.5%	10.0%	10.5%	10.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	13.0%	11.8%	11.0%	11.5%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	12.2%	13.8%	13.0%	12.5%	13.0%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	5.6%	7.0%	10.5%	9.5%	9.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	12.4%	11.5%	9.5%	10.0%	11.0%
Average	10.6%	11.8%	11.0%	10.9%	12.4%	12.3%	11.7%	11.2%	12.1%	12.6%	11.3%	11.9%	11.8%	11.3%	**11.6%**	**11.8%**	**11.6%**	**10.3%**	**11.3%**
Composite															**11.7%**	**11.8%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average
Comparison Group																
Cleco	177.3%	174.9%	156.2%	162.2%	167.8%	170.8%	182.5%	172.3%	222.8%	224.3%	154.1%	134.5%	176.9%	176.6%	181%	173%
DPL Inc	176.6%	206.0%	195.6%	213.1%	214.4%	221.4%	231.2%	215.4%	313.8%	403.9%	639.5%	241.3%	271.8%	318.5%	239%	375%
Duquesne Light Holdings	137.4%	150.8%	130.4%	150.6%	163.1%	165.4%	196.7%	205.2%	255.5%	217.2%	218.7%	220.8%	240.4%	217.9%	177%	223%
Empire District	184.2%	178.0%	142.9%	142.3%	142.7%	137.6%	168.0%	176.5%	183.2%	162.0%	131.7%	132.7%	143.7%	148.5%	162%	144%
Hawaiian Electric	170.8%	153.9%	141.2%	149.1%	147.0%	147.1%	154.1%	131.8%	126.7%	145.1%	153.3%	150.9%	178.8%	181.2%	147%	162%
Northeast Utilities	154.2%	149.4%	127.0%	123.5%	94.5%	64.3%	90.7%	113.3%	136.4%	129.0%	99.4%	95.3%	105.5%	108.4%	118%	108%
Pepco Holdings	159.6%	162.2%	135.5%	138.3%	160.7%	151.0%	161.3%	166.1%	138.8%	124.4%	109.9%	102.9%	109.2%	121.9%	150%	114%
PNM Resources	71.9%	83.8%	86.6%	95.3%	108.3%	105.7%	105.7%	84.9%	94.1%	122.7%	94.5%	93.5%	124.3%	147.2%	96%	116%
Puget Energy	149.2%	146.4%	111.7%	119.5%	130.0%	155.2%	169.7%	145.8%	143.4%	143.5%	125.9%	128.9%	137.5%	132.7%	141%	134%
Average	167%	169%	149%	157%	155%	151%	171%	169%	206%	214%	233%	163%	186%	192%	**171%**	**197%**
Composite															**177%**	**197%**
Grant Comparable Gas Group																
AGL Resources	181.0%	195.4%	169.2%	171.8%	189.1%	182.8%	183.4%	168.6%	167.6%	183.6%	171.2%	188.4%	184.0%	190.9%	179%	184%
Atmos Energy Corp	158.4%	193.5%	186.4%	195.7%	247.7%	241.4%	245.6%	216.5%	166.6%	170.4%	150.0%	152.3%	146.9%	144.9%	202%	153%
Cascade Natural Gas	171.6%	183.2%	156.3%	155.9%	155.7%	169.4%	164.6%	167.4%	162.2%	184.4%	185.9%	195.6%	204.1%	195.1%	167%	193%
Laclede Gas Company	158.3%	187.2%	178.2%	162.8%	167.7%	174.8%	174.5%	159.2%	141.2%	154.7%	145.1%	168.6%	179.4%	178.6%	166%	165%
New Jersey Resources	161.0%	185.5%	162.0%	178.9%	190.4%	228.5%	224.8%	224.0%	226.7%	223.6%	220.5%	244.4%	251.5%	274.6%	201%	243%
Nicor, Inc	178.9%	215.8%	194.6%	186.8%	220.0%	241.6%	259.6%	226.1%	226.5%	239.1%	198.9%	184.8%	210.0%	222.1%	219%	211%
Northwest Natural Gas	161.9%	175.8%	161.4%	145.8%	156.1%	173.3%	169.0%	140.6%	129.2%	132.9%	144.8%	144.0%	153.4%	171.8%	155%	149%
Piedmont Natural Gas	179.7%	213.6%	186.0%	181.6%	182.8%	216.6%	222.2%	212.9%	195.4%	198.9%	186.4%	211.3%	212.1%	207.7%	199%	203%
South Jersey Industries	154.2%	174.6%	141.0%	142.1%	145.7%	178.4%	208.5%	202.0%	195.9%	204.5%	185.4%	170.1%	195.2%	221.2%	175%	195%
Southwest Gas	81.3%	99.8%	102.7%	103.5%	121.0%	128.7%	139.3%	146.9%	120.4%	127.0%	123.4%	118.1%	126.9%	134.8%	117%	126%
WGL Holdings	173.5%	188.9%	165.4%	164.1%	178.3%	199.1%	197.1%	176.3%	177.5%	176.9%	152.4%	162.3%	175.0%	183.0%	180%	170%
Average	160%	183%	164%	163%	178%	194%	199%	186%	174%	181%	169%	176%	185%	193%	**178%**	**181%**
Composite															**178%**	**177%**

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299.2%

Source: Standard & Poor's Analyst's Handbook, 2006 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.9	0.92	B+	B
Grant Comparable Gas Group	2.1	0.86	B+	B+
Unisource Energy	3.0	0.75	C++	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

Exhibit___(DCP-1)
Schedule 13

UNS GAS
TOTAL COST OF CAPITAL

ITEM	AMOUNT ($000)	PERCENT	COST RATE		WEIGHTED COST	
Long-Term Debt	$98,859	55.33%	6.60%		3.65%	
Common Equity	$79,804	44.67%	9.50%	10.50%	4.24%	4.69%
Total	$178,663	100.00%			**7.89%**	**8.34%**
					8.12% Mid-point	

Exhibit___(DCP-1)
Schedule 14

UNS GAS
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	55.33%	6.60%	3.65%	3.65%	
Common Equity	44.67%	10.00%	4.47%	7.44%	(1)
TOTAL CAPITAL	100.00%		8.12%	11.10%	

(1) Post-tax weighted cost divided by .6 (composite tax factor)

Pre-tax coverage = 11.10%/3.65%
3.04 X

Standard & Poor's Utility Benchmark Ratios:

	BBB	A
Pre-tax coverage (X) Business Position:		
5	2.4 - 3.5x	3.5 - 4.3x
Total Debt to Total Capital (%) Business Position		
5	50- 60%	42 - 50%

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

SURREBUTTAL

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

APRIL 4, 2007

TABLE OF CONTENTS

SCHEDULE

INTRODUCTION

Q. Please state your name and address.

A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of Technical Associates, Inc. My business address is 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. Are you the same David C. Parcell who filed Direct Testimony on behalf of the Commission Staff in this proceeding?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. My current testimony is Surrebuttal Testimony in response to the Rebuttal Testimony of UNS Gas witness Kentton C. Grant. I also respond to UNS Gas' proposal to apply the Company's cost of capital to a fair value rate base.

Q. What aspects of Mr. Grant's Rebuttal Testimony do you respond to in this Surrebuttal Testimony?

A. My Surrebuttal Testimony responds to the following general areas of Mr. Grant's Rebuttal Testimony:

Cost of Common Equity;
Capital Structure; and,
Financial Integrity/Capital Attraction of UNS Gas.

COST OF COMMON EQUITY

Q. What are the primary differences in your cost of equity recommendations and the cost of equity recommendations of Mr. Grant?

A. The primary difference in our respective cost of equity recommendations revolves around our Capital Asset Pricing Model ("CAPM") analyses. As I indicated in my Direct Testimony (Page 37, lines 18-20) and as Mr. Grant acknowledges in his Rebuttal Testimony (Page 17, Lines 12-14), our respective Discounted Cash Flow ("DCF") results are very similar, as follows:

Parcell	9.25% -- 10.50%
Grant	9.10% -- 10.50%

This indicates that Mr. Grant and I agree with regard to our DCF results. However, it appears that Mr. Grant does not give any weight to his DCF results, as his recommended 11.0 percent cost of equity for UNS Gas exceeds the median of his DCF results (9.9 percent) and appears to rely exclusively on the median of his CAPM analysis (11.0 percent). This exclusive reliance on his CAPM results in an excessive cost of equity recommendation by Mr. Grant.

Q. Aside from your concerns with Mr. Grant's exclusive reliance on the CAPM methodology, do you have any comments about Mr. Grant's CAPM methodology and his comments on your CAPM methodology in his Rebuttal Testimony?

A. Yes, I do. As I indicated in my Direct Testimony (Page 37, Lines 28-31 and Page 38, Lines 1-4) and as Mr. Grant acknowledges in his Rebuttal Testimony (Page 17, Lines 23-25), the primary differences in our respective CAPM methodologies are 1) his use of a risk free rate (5.3 percent) which is outdated and exceeds the current level of U.S.

Treasury bond yields; and 2) his use of an equity risk premium (7.1 percent) that relies exclusively on the arithmetic means of common stock returns and bond returns over the period 1926-2005.

Q. Mr. Grant claims, on pages 18-19, that it is appropriate to use only arithmetic returns, and ignore geometric (compound) returns in deriving the risk premium component of the CAPM. Do you have any comments on this claim?

A. Yes, I do. What is important is not what Mr. Grant and I believe, but what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, when they make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns (see for example, Schedule 1 which shows historic performance information for one of the nation's largest mutual funds). Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors and, thus, only arithmetic returns are appropriate in a CAPM context.

Q. Does Mr. Grant use Value Line information in his cost of capital analyses?

A. Yes, he does.

Q. Do the Value Line reports cited in his testimony show historic growth rates for the gas utilities?

A. Yes, they do.

Q. Do these Value Line reports show historic returns on an arithmetic basis?

A. No, they do not.

Q. Do the Value Line reports show historic returns on a geometric, or compound growth rate basis?

A. Yes, they do. See Schedule 2, which describes Value Line's method of calculating growth rates. As a result, any investor reviewing Value Line, as Mr. Grant does, would be using geometric growth rates, not arithmetic growth rates.

Q. Is it your position that only geometric growth rates be used?

A. No. I believe that both arithmetic and geometric growth rates should be used. This is the case since investors have access to both and presumably use both.

Q. But does not Mr. Grant cite (pages 18-19) his perception that financial literature requires that arithmetic returns be used for this purpose?

A. He does state this is his testimony. However, the cost of capital determination is not an academic exercise made in some laboratory or university classroom. The true cost of equity is made in the "laboratory" of the financial markets, based on the ongoing inter-play of countless investors, each with their own agendas and beliefs. This is verified by the fact that each time a share of stock is purchased by one investor, it is simultaneously being sold by another investor, indicating that their respective views at that time differ.

Again, investors have access to both arithmetic and geometric growth rates. In all likelihood, there is more geometric growth readily available to investors (e.g., mutual fund reports and Value Line) than arithmetic growth.

Q. Mr. Grant also takes issue with your comparable earnings analysis. Do you have any response to his assertions?

A. Yes, I do. Mr. Grant apparently believes that, if natural gas distribution utilities, such as UNS Gas, have and are earning returns on equity of over 10 percent and simultaneously are enjoying a market-to-book ratio of about 180 percent, then the earned levels represent the cost of capital for the gas utilities. I disagree with this position. Investors know that the vast majority of utilities are regulated based upon the book value of their assets (i.e., rate base) and their liabilities (i.e., capitalization). It is logical and intuitive that investors would only pay a stock price that substantially exceeds book value for a utility if there is an expectation that the company is earning a return that exceeds its cost of capital. Mr. Grant ignores this in his Rebuttal Testimony.

Q. Mr. Grant also asserts, on pages 19-20, that you did not take into account any "Company-specific risk factors" in your cost of equity recommendation. Do you have any response to this assertion?

A. Yes, I do. The primary "Company-specific risk factor" that Mr. Grant cites is the "size" of UNS Gas. Mr. Grant apparently believes that UniSource Energy's decision to maintain UNS Gas as a separate subsidiary, in contrast to merging it into Tucson Electric Power and/or UniSource Energy, should have the effect of raising its cost of equity. I disagree with this assertion. UNS Gas does not raise equity capital in the marketplace; rather it is raised by UniSource Energy based on the combined financial strength of all of its operations. If UNS Gas and every other subsidiary of UniSource Energy received a higher cost of equity due to their respective "small" sizes, each subsidiary, as well as UniSource Energy as a whole, would earn an excessive return.

Q. Mr. Grant also claims, on page 20, lines 2-7, and again on page 21, lines 19-27, that your cite of a 2003 Standard and Poor's report that is no longer relevant. Do you have any response to this assertion?

A. Yes, I do. The source of the 2003 Standard & Poor's ("S&P") report is UNS Gas' response to STF 7.2. Since there have been no subsequent descriptions of the Company, it is evident from the S&P reports supplied by the Company in its DR response that S&P does not perceive that UNS Gas' financial status has changed since the cited report was prepared. The absence of any modification of these quotes by S&P is indicative that this agency's position of the Company has not changed since the cited report.

CAPITAL STRUCTURE

Q. What are Mr. Grant's comments on your capital structure recommendation?

A. Mr. Grant objects to my capital structure recommendation, on Page 20, Lines 9-13, by noting that I use the actual capital structure of UNS Gas rather than the hypothetical capital structure proposed by the Company. However, as was the case in his Direct Testimony, he has offered no compelling reasons – indeed no reasons at all – why the Commission should ignore the Company's actual capital structure and utilize a hypothetical capital structure that contains more equity than UNS Gas, Tucson Electric Power, or UniSource Energy.

FINANCIAL INTEGRITY/CAPITAL ATTRACTION

Q. Mr. Grant claims, on page 21, lines 1-15, that UNS Gas would not likely earn the return you recommend as a result of recommendations of other Staff witnesses. Do you have any response to this?

A. Yes, I do. The respective recommendations of other Staff witnesses in this proceeding reflect their own recommendations based upon their own analyses of UNS Gas' application and their own implementation of proper rate-making standards. To the extent that the Commission adopts any or all Staff recommendations, this is reflective of regulatory acceptance of the positions taken by Staff. Any corresponding reduction in the Company's potential earned rate of return would thus be appropriate from a regulatory and rate-making standpoint.

UNS GAS PROPOSAL TO APPLY COST OF CAPITAL TO FAIR VALUE RATE BASE

Q. What is your understanding of UNS Gas' proposal to apply the Company's cost of capital to a fair value rate base?

A. According to the Rebuttal Testimonies of James S. Pignatelli (page 2, lines 18-20) and Kentton C. Grant (page 28, lines 1-20), UNS Gas is proposing that the total cost of capital for the Company be applied to the "fair value" of the Company's rate base. This request is apparently being made in response to a recent Arizona Court of Appeals decision regarding Chaparral City Water Company. According to UNS Gas witnesses' interpretation of this decision, the Commission "must use fair value rate base to set rates per the Arizona Constitution."

Q. Have you reviewed this decision and do you have any comments on your understanding of its implications for this case?

A. Yes, I do. As was the case for Mr. Grant's testimony, my "non-legal understanding" of this decision is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree with Mr. Grant that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

My "non-legal understanding" of the Court decision indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base' and thus was appropriately applied here to the OCRB." The decision went on to state "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether the cost of capital is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the entire concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet. From a financial, as well as regulatory, perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The "excess" of fair value rate base over original cost rate base is not financed with investor-supplied funds and, indeed, the excess is not financed at all. As a result, the cost of capital cannot be applied to the fair value rate base since there is no financial link between the two concepts.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory, as well as regulatory precedent, indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world) the link between cost of capital and rate base satisfies this financial and regulatory objective.

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a proposed solution for the Commission to account for the use of a fair value rate base in setting rates for UNS Gas?

A. Yes, I do. Since the differential between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate to assume that this excess has no cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the excess of fair value rate base over the original cost rate base. Such a procedure would still provide for a return being earned on all investor-supplied funds and thus be consistent with financial and regulatory standards.

Q. Has the Staff made such a proposal in this proceeding?

A. Yes, it has. Staff witness Ralph Smith has re-cast my cost of capital calculation in a fashion that incorporates my surrebuttal position. As this indicates, the "fair value cost of capital" for UNS Gas is 6.81 percent.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Vanguard 500 Index Fund Investor Shares (VFINX)

Performance

The performance data shown represent past performance, which is not a guarantee of future results. Investment returns and principal value will fluctuate, so that investors' shares, when sold, may be worth more or less than their original cost. Current performance may be lower or higher than the performance data cited.

Average Annual Returns—Updated Monthly as of 02/28/2007

Important fund performance information

Display data in bar chart

	1 Year	3 Year	5 Year	10 Year	Since Inception 08/31/1976
500 Index Fund Inv	11.80%	8.95%	6.69%	7.55%	12.14%
S&P 500 Index*	11.97%	9.10%	6.82%	7.63%	—

After-Tax Returns—Updated Quarterly as of 12/31/2006

Learn more about after-tax returns

	1 Year	3 Year	5 Year	10 Year	Since Inception 08/31/1976
500 Index Fund Inv					
Returns Before Taxes	15.64%	10.30%	6.07%	8.34%	12.23%
Returns After Taxes on Distributions	15.34%	10.00%	5.72%	7.85%	—
Returns After Taxes on Distributions and Sale of Fund Shares	10.53%	8.83%	5.11%	7.12%	—
Average Large Blend Fund					
Returns Before Taxes	14.15%	10.05%	5.92%	7.79%	—
Returns After Taxes on Distributions	—	—	—	—	—
Returns After Taxes on Distributions and Sale of Fund Shares	—	—	—	—	—

Recent Investment Returns

	Year-to-Date as of 03/19/2007	Year-to-Date as of 02/28/2007	Previous Month—February	Three-Month Total as of 02/28/2007
500 Index Fund Inv	−0.76%	−0.51%	−1.97%	0.88%
S&P 500 Index*	—	−0.47%	−1.96%	0.92%

See cumulative, yearly, and quarterly historical returns

Important Fee Information

Account Maintenance Fee

Each Vanguard index fund (except the REIT Index Fund) charges a maintenance fee if the balance is below $ 10,000. The fee of $10 is deducted annually, or $2.50 per quarter for funds that distribute dividends more than once a year. If your distribution is less than the fee, a fraction of a share may be redeemed to make up the difference. Note that this fee applies to each fund account. For example, if you have an account with two index funds, each with less than $10,000, you will be charged a total of $20 a year. Similarly, if you have the same index fund in two different accounts (e.g., individual account, joint account, traditional IRA, Roth IRA, or any two accounts under different registrations or account numbers), each with less than $10,000, you will be charged a total of $20 a year.

More fee details

Growth of $10,000

Compare the growth of a hypothetical $10,000 investment in this fund with the growth of the same amount in up to 2 other Vanguard® funds and a benchmark. To get an accurate comparison, choose a time range that covers the number of years all funds have been in existence. Move your mouse over the graph to see the changes in returns.

Figures include reinvestment of dividends and capital gains but don't reflect the effect of any sales charges or redemption fees, which would lower these figures. The initial investment used in the graph may be higher or lower than the initial minimum amount required to invest in each fund. The performance of an index is not an exact representation of any particular investment, as you cannot invest directly in an index. Past performance cannot be used to predict future returns. The investment return and principal value of an investment will fluctuate, so an investor's shares, when sold, may be worth more or less than their original cost. **Click a fund name to view standardized performance.**

Before making an investment decision, it's important to check the fund's prospectus for factors such as investment objectives, costs and expenses, liquidity, fluctuation of principal or return, and tax features. Use our Fund Compare tool for more information about Vanguard funds.

*A widely used barometer of U.S. stock market performance; as a market-weighted index of leading companies in leading industries, it is dominated by large-capitalization companies.

Glossary

average annual total return

Provides the average return of the fund over a specific period of time. For example, if a fund's net asset value (NAV) started at $10 and after 3 years it rose to $15, the fund's average annual return would be about 14.47%. This number shows how much the fund averaged each year during the 3-year period to get to its $15 NAV.

Average annual returns are always calculated as of the end of each month.

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index, and the risk-free rate of return of a three-month Treasury Bill. For example, if a stock has a beta of 1.5, it would be expected to gain 15% when the index gains 10%. If however, the stock actually gains 20%, this excess return represents the stock's alpha. Value Line expresses alpha as an annualized figure.

American Depository Receipts (ADRs) - Since most other nations do not allow stock certificates to leave the country, a foreign company will arrange for a trustee (typically a large bank) to issue ADRs (sometimes called American Depository Shares, or ADSs) representing the actual, or underlying, shares. Each ADR is equivalent to a specified number of shares (the ratio is shown in a footnote on the Value Line page).

American Stock Exchange Composite - A market-capitalization weighted index of the prices of the stocks traded on the American Stock Exchange.

Annual Change D-J Industrials - The annual change from year end to year end in the Dow Jones Industrial Average, expressed as a percentage.

Annual Change in Net Asset Value (Investment Companies) - The change in percentage terms of the net asset value per share at the end of any given year from what it was at the end of the preceding year, adjusted for any capital gains distributions made during the year.

Annual Rates of Change (Per Share) - Compounded annual rates of change of pershare sales, cash flow, earnings, dividends, and book value (or other industry-specific per-share figures) over the past ten years and five years and estimated over the coming three to five years. All forecasted rates of change are computed from the average figure for the past three-year period to an average for a future three-year period. If data for a three-year base period are not available, a two- or one-year base may be used.

Arbitrage - The simultaneous purchase of an asset in one market and sale of the same asset, or assets equivalent to the asset purchased, in another market. Often referred to as "classical arbitrage," this type of transaction should result in a risk-free profit. Risk Arbitrage refers to transactions in stocks involved in takeover activity.

Arbitrageur - A person or organization that engages in arbitrage activity.

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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA CORPORATION COMMISSION.	DOCKET NO. G-04204A-06-0463 **COMMISSION STAFF'S NOTICE OF ERRATA FILING**
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

On February 9, 2007, the Arizona Corporation Commission ("Commission") Staff filed its direct testimony in the above-captioned matters. Through this Errata Filing, Staff desires to correct several errors appearing in the testimony and schedules of Mr. David C. Parcell. First, Staff files a revised Schedule 2 which corrects for several omissions in the original schedules. Second, the following corrections should be made to Mr. Parcell's written testimony:

1. Page 15, line 9: delete "Smith"; insert "Ruback."
2. Page 29, line 9: delete "4.84"; insert "4.83."

Arizona Corporation Commission
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3. Page 33, line 4: delete "11.7"; insert "11.5."

RESPECTFULLY SUBMITTED this 13th day of February 2007.

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ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.9%	2.5%	5.5%	3.3%	4.2%
2005	3.2%	3.2%	5.1%	3.4%	5.4%
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.9%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	4.0%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.1%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.6%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.4%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	4.2%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.8%	3.1%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	2.0%	5.2%	4.7%	0.4%	-4.4%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec					5.62%	5.81%	6.05%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.42%
4th Qtr.	1,230.47	2,178.67	10,615.78	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.88%
3rd Qtr.	1,288.40	2,141.97	11,584.69	1.91%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

EXHIBIT
S-39
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 9, 2007

TABLE OF CONTENTS

ATTACHMENT

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013
AND G-04204A-05-0831

On July 13, 2006, UNS Gas, Inc. ("UNS") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. Included in this application is a request for approval of UNS' proposed Demand-side Management ("DSM") programs, including movement of its existing Low-Income Weatherization ("LIW") program into the new DSM portfolio. Funding is to be increased for the LIW program and UNS proposes that an emergency bill payment component be added. In addition, UNS proposes to change the existing Customer Assistance Residential Energy Support ("CARES") program from a six-month per therm discount on the first 100 therms to a year-round discount on the monthly customer charge.

On September 8, 2006, the Commission granted the Motion to Consolidate the Rate Case (Docket No. G-04204A-06-0463) with the PGA Case (Docket No. G-04204A-06-0013) and the Prudence Case (G-04204A-05-0831). Having read UNS' Direct Testimony, Staff recommends the following:

1. UNS should continue to work toward expanding participation in the CARES program to additional eligible households.

2. The CARES program monthly customer charge should remain at its current level, and the current per therm discount should be retained.

3. The deferred account for the CARES program should be discontinued.

4. UNS should submit detailed DSM program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case.

5. Emergency bill assistance should not be included in the DSM portfolio. Emergency bill assistance, in the amount of $21,600, should be funded from base rates and combined, as an additional funding source, with the existing Warm Spirit emergency bill assistance program.

6. UNS should file a comprehensive DSM portfolio plan for Commission approval, along with detailed program proposals for each of the new DSM programs it wishes to pursue.

7. When filing its detailed DSM program proposals, UNS should include the data required to calculate the cost-effectiveness of each program on a Societal Test basis.

8. As part of its DSM portfolio filing, UNS should provide information for the LIW program, including marketing, verification and inspection, and cost-effectiveness.

9. UNS should create a monitoring plan for each DSM program and describe these plans in each program proposal.

10. UNS should submit semi-annual DSM reports.

11. UNS should recover its costs for all of its DSM programs through a separate DSM adjustment mechanism. The initial DSM charge, to fund the ongoing LIW program, should be set at $0.00082 per therm.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst II.

A. In my capacity as a Public Utilities Analyst II, I review monthly filings of purchased gas adjustors. My duties include reviewing annual utility affiliated interest reports for compliance and evaluating demand-side management programs submitted for approval to the Commission.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated magna cum laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006.

Q. What is the subject matter of this testimony?

A. This testimony will present Staff's analysis and evaluation of UNS Gas, Inc.'s ("UNS") low-income assistance programs and proposed demand-side management ("DSM") programs, including movement of its Low-Income Weatherization ("LIW") program from the Low-Income Assistance programs into the DSM portfolio.

LOW-INCOME ASSISTANCE PROGRAMS

Q. What low-income assistance programs does UNS provide for its customers?

A. UNS provides its Customer Assistance Residential Energy Support ("CARES") discount program, the Warm Spirit emergency bill assistance program and the Low-Income Weatherization program, which helps low-income customers to improve the energy efficiency of their homes. UNS has proposed moving the LIW program into its DSM portfolio, so the LIW program will be discussed later in this testimony, in the section on demand-side management.

Q. Please describe the current CARES program.

A. Households with income equal to 150% percent, or less, of the Federal Poverty Guidelines can receive a $0.15 per therm discount from November through April. This per therm discount only applies to the first 100 therms used. Due to changes made to certification procedures in 2004, participants can enroll in less than 20 days; the requirements for yearly recertification were also eased. (Tobin L. Voge, p. 10; Gary A. Smith testimony, pp. 9-10; Decision No. 67434, December 3, 2004)

Q. How many UNS customers participate in the CARES program, and how has participation changed over time?

A. In January 2004, CARES participation was at 2,251, or 1.9% of residential customers. Two years later, as of January 2006, CARES-enrolled households numbered 5,670, or 4.4% of residential customers; by June 2006, participation was 5,989, or 4.6% of residential customers. Staff recognizes the improvement and recommends that UNS continue to work toward expanding participation in the CARES program to additional eligible households. (Semi-Annual Reports, UNS Gas, Inc.'s and UNS Electric, Inc.'s CARES Discount Programs, August 6, 2004, January 30, 2006 and July 27, 2006)

Q. Does UNS propose to change the CARES program?

A. Yes. UNS proposes to discount the monthly residential customer charge by $6.50 on a year-round basis and to eliminate the $0.15 per therm discount. (Tobin L. Voge, p. 10; Gary A. Smith testimony, p. 10)

Q. Has UNS proposed other changes that would affect the monthly customer charge paid by CARES customers?

A. Yes. In addition to the $6.50 year-round discount, UNS has requested increases in the monthly residential customer charge for all customers, from $7 year-round to $20, April through November, and $11, December through March. (UNS Gas, Inc. PPS-1 Pricing Plan Summary; Testimony of Tobin L. Voge, p. 9-10).

If the proposed discount and monthly charges were both approved, they would:

(i) increase the monthly customer charge from $7 to $13.50 for eight months of the year;

(ii) decrease the monthly customer charge from $7 to $4.50 for four winter months; and

(iii) increase the annual amount paid in monthly residential customer charges from $84 to $126.

Please see, also, testimony of Staff Witness Steve Ruback regarding Staff recommendations concerning changes to the monthly service charge.

Q. Has UNS proposed other changes that would affect the per therm charge paid by CARES customers?

A. Yes. In addition to proposing elimination of the CARES per therm discount, UNS proposes to decrease the year-round margin, for all customers, from $0.3004 to $0.1862. (UNS Gas, Inc. PPS-1, effective December 3, 2004; Schedule H-3) For CARES customers this would mean an increase of $0.0358 per therm, from November through April, for the first 100 therms used; for usage over 100 therms, it would mean a decrease of $0.1142 per therm.

Q. How many therms does the average CARES customer use?

A. The average CARES customer used 64 therms per month during winter of the test year. (Tobin L. Voge testimony, p 10)

Q. Do the proposed changes benefit UNS CARES program participants?

A. The proposed changes do not benefit most CARES customers. The change in discount is projected to increase savings for the average CARES participant by 34%. (Tobin L. Voge testimony, p. 10) However, these savings are based on discounting increased monthly fees; on an annual basis, CARES customers would be paying more in monthly customer charges, even with the year-round $6.50 discount. Also, the average CARES customer would be paying more, per therm, during the November through April period, experiencing a decreased per therm rate only on usage over 100 therms. In general, higher-usage customers would benefit, while lower-usage customers would see increases.

Q. What would be the impact of the changes on average monthly bills for CARES customers?

A. From April through November, with the higher monthly charge, CARES customers using the fewest therms (5-50 therms) would experience increases ranging from $0.79 (3.60%) to $5.93 (69.74%). Higher-usage customers (75-500 therms) would experience decreases ranging from $2.06 (6.98%) to $50.58 (32.17%).

During the December through March period, with the lower monthly charge, both lower-usage (5-50 therms) and higher-usage (250-500 therms) customers would experience decreases -- $0.69 (4.74%) to $2.32 (29.92%) for lower-usage customers, and $1.12 (5.11%) to $44.54 (31.33%) for higher-usage customers. Customers in the middle range, 75-100 therms, would experience increases of $0.22 (1.20%) to $1.12 (5.11%). (UNS, Schedule H-4, Typical Bill Comparison, Present and Proposed Rates.)

Q. Does UNS anticipate any impact on customer gas usage from the proposed change to the CARES program?

A. UNS has not done the price elasticity study that would be required to quantify the impact of the proposed change on gas usage. (UNS' response to Staff's data request STF 12.2)

Q. What other benefits are there to participating in the CARES program?

A. CARES participants are exempt from paying the current Purchased Gas Adjustor ("PGA") surcharge. It should be noted that the PGA surcharge will end after April 2007 (Decision No. 69169).

Q. Does Staff recommend that the changes be made to the CARES program as proposed by UNS?

A. No. The changes proposed by UNS would have a disproportionate impact on low-usage CARES customers and eliminate the incentive to conserve provided by the current per therm discount. The typical bill comparison shows that customers using the fewest therms would experience the largest percentage increases in their monthly bills, particularly during the eight months of higher monthly customer charges. (Schedule H-4, p. 2; Schedule H-5, p. 2)

Another potential negative impact could occur in November and April, when some UNS-served areas are still experiencing cold weather; during these months, CARES customers would be paying both the higher monthly charge and the increased margin rate for less than 100 therms. The UNS response to STF 15.5 includes a table showing proposed increases ranging from 46% to 86.19% for CARES customers using 100 therms or less during November and April. This would both impact low-usage customers and run counter to the practice of targeting CARES relief for colder months, in order to meet home heating needs.

Staff recommends that the CARES program monthly customer charge remain at its current level, as an added benefit to CARES customers, and that the current per therm discount be retained.

Q. Would an adjustment to test year data be required with respect to Staff's recommendations on CARES discounts?

A. Staff's proposal will probably result in an adjustment to test year data, depending on the level of monthly customer charge(s). The level of adjustment will be discussed in Staff's surrebuttal testimony.

Q. What impact has the CARES program surcharge exemption had on the PGA bank balance?

A. From November 2005 through March 2006 the reduced PGA bank balance collection was $308,731, while the currently projected reduction for all of 2006 is nearly $568,000. (UNS' responses to Staff's data request STF. 12.1; James Pignatelli testimony, p. 19) As of November 2006, UNS reported an over-collected bank balance of $4,727,307.36. (November 2006 UNS Monthly Purchased Gas Adjustor Report).

Q. How did UNS treat CARES discounts and program expenses in its application?

A. On October 29, 1999, Decision No. 59875 ordered that Citizens record income and expenses for its Low-Income Residential Assistance Programs in a deferred account and compare the total to the revenues collected. The UNS CARES deferred account functions as a tracking account, resulting in a balance between amounts spent and amounts accrued. In the current rate case, UNS is seeking to recover a balance of $107,477 on an amortized basis over three years. (Karen Kissinger testimony, p.15; UNS response to RUCO's data request 1.10, UNS Gas CARES Deferral Calculation Adjusted Schedule, December 31, 2005; also Change to Residential Customer by Rate – All Regions)

It appears that the deferred account was originally ordered to ensure that monies collected for low-income residential assistance programs were actually spent on those programs.

However, in 2005, UNS spent $175,562 more on the CARES program than it collected. Given the increased CARES enrollment levels and the attendant increases in discounts and program expenditures, Staff recommends that UNS discontinue the deferred account.

Q. Please describe the Warm Spirit program.

A. The UNS Warm Spirit program provides emergency bill assistance to low-income customers, using shareholder funds to match customer donations. UNS also provided a one-time donation of $50,000 in 2004. Matching fund donations range between $20,000 and $25,000 yearly, with the funds distributed by local social service agencies. UNS does not propose any changes to the Warm Spirit program. (Gary A. Smith testimony, pp. 10-11; James S. Pignatelli testimony, pp. 18-19) However, Staff proposes that the $21,600 in emergency bill assistance proposed by UNS as a part of the LIW program be moved, instead, into the Warm Spirit program as an additional source of funding.

DEMAND-SIDE MANAGEMENT ("DSM")

<u>Benefits and Costs of DSM</u>

Q. What is DSM?

A. DSM is planning, implementation and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand and/or to reduce energy consumption in a cost-effective manner. DSM may include the following: (1) energy efficiency, meaning products, services or practices that provide equal or superior service while consuming less energy; (2) load management, meaning actions by a utility to reduce peak demands or improve system operating efficiency; and (3) demand response, meaning intentional modification of customer energy consumption patterns, including the timing or quantity of demand.

Q. Do any of the DSM programs proposed by UNS Gas shift peak load or reduce peak demand?

A. The main purpose of the proposed UNS DSM programs is to cut down on the number of therms consumed; however, UNS states that, although no demand analysis has been prepared to measure the effects, a gas peak reduction would also result. (UNS' response to Staff's data request, STF 12.3)

Q. Do DSM programs benefit both UNS and the rest of society?

A. Yes. Benefits to both UNS and society include meeting the demand for natural gas less expensively than through purchasing additional supplies of natural gas and delaying the need for construction of new infrastructure, including plants, storage facilities and pipelines. Societal benefits also include decreased pollution and emissions of carbon dioxide and methane, both greenhouse gases (see www.naturalgas.org). In addition, DSM programs can assist in conserving a finite natural resource.

Q. Why should UNS and Staff consider the benefits and costs of DSM to society as well as to UNS?

A. Since the benefits and costs of a DSM program for society may be different from those for a utility, the benefits and costs for both should be considered. In its 1991 resource planning decision, the Commission adopted the use of the Total Societal Test. (Decision No. 57589, dated October 29, 1991)

Q. Are avoided environmental impacts included in evaluating the cost-effectiveness of a DSM program?

A. Yes, as part of the societal benefits. The Commission directed that environmental concerns be considered in resource planning (Decision No. 57589, dated 10/29/91), and DSM is a part of resource planning.

Q. What are the societal costs of a DSM program?

A. The societal costs of a DSM program consist of the incremental costs of the DSM program (including incremental utility costs and incremental customer/vendor costs). Such costs may include the cost of equipment, the cost of installation, training costs for workers who install or repair energy-efficient equipment and administrative costs. Incentives to customers to participate in a DSM program are transfer payments, not societal costs. Transfer payments are transfers of income from one person or organization to another, without goods or services being supplied in exchange for these transfers.

UNS' Current DSM Program

Q. What has UNS proposed regarding DSM?

A. UNS has proposed a preliminary portfolio plan for four new DSM programs, a DSM cost recovery mechanism, and movement of its enhanced and modified LIW program into the DSM portfolio. UNS proposes to file the four new DSM program proposals with the Commission 120 days after resolution of the UNS Electric rate case, Docket No. E-04204A-06-0783. (UNS' response to Staff's data request JM 8.12).

Q. Does Staff agree with UNS waiting until conclusion of the UNS Electric rate case?

A. No. Staff recommends that UNS submit detailed program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case, in which a decision is not expected until 2008.

Q. Please provide background on UNS' current DSM program.

A. The only DSM-type program currently provided by UNS is its Low-Income Weatherization ("LIW") program, currently part of UNS' customer assistance programs. This program was in place when UniSource Energy Corporation purchased Citizen's Communications Company in 2003. (UNS' response to Staff's data request JM 8.5).

Q. What is the current level of funding for LIW, and how is it funded?

A. The annual budget is $75,000 and is funded through operating expenses, in base rates. (Gary A. Smith testimony, p. 11; UNS' response to Staff's data request JM 8.6.) Although not currently an approved DSM program, UNS has now asked for Commission approval of LIW as a DSM program, also proposing a $60,000 increase in budget and transfer into the proposed DSM portfolio. (Gary A. Smith testimony, pp. 11-13.)

Q. Please describe the current LIW program.

A. In its current form, the LIW program provides energy efficiency improvements to homes occupied by UNS customers with household incomes at or below 150% of the Federal Poverty Guidelines (FPG). As an example, 150% of the FPG for a family of four would be $30,000. (http://liheap.ncat.org/profiles/povertytables/FY2007/pop130.htm) UNS provides up to $2,000 for weatherization of each household, installing measures that include improved insulation, weather stripping and furnace replacement. (Gary A. Smith Testimony, p. 12.)

Q. Please describe the nature of the enhancement proposed by UNS.

A. UNS proposes to increase funding for LIW by $60,000, from $75,000 to $135,000, and to allocate $21,600 of this amount to a new emergency bill assistance component. (Gary A. Smith Testimony, p. 11)

UNS' Emergency Bill Assistance

Q. Please describe the emergency bill assistance component of the proposed, enhanced, Low-Income Weatherization program.

A. UNS has proposed allocating $21,600 of the LIW budget to a new emergency bill assistance program for utility customers with household incomes at or below 150% of the FPG. Customers must present a delinquent or unpaid bill and may receive no more than $400 in assistance during any 12-month period. Administration is to be done by community action agencies under contract to UNS. (Gary A. Smith testimony, p. 12.)

Q. Would the LIW emergency bill assistance program be in addition to the emergency bill assistance program already in place as part of the Warm Spirit program?

A. Yes. (Gary A. Smith testimony, pp. 10-11)

Q. How do the existing (Warm Spirit) and proposed (LIW) emergency bill assistance programs differ?

A. The existing Warm Spirit program is funded, as stated above, by customer and shareholder donations, and the funds are provided to community action agencies. The Low-Income Weatherization program, if approved as a DSM program, would be funded through the proposed DSM adjustor, and the funds would be distributed through UNS' Weatherization

Program partners, also community action agencies. Income requirements (150% of FPG) for the two emergency bill assistance programs would be the same. (UNS' response to Staff's data request JM 8.2)

Q. Is emergency bill assistance a Demand-side Management ("DSM") program?

A. No. Emergency bill assistance, although a benefit for customers in crisis situations, is a low-income assistance program and should not be included in the DSM portfolio. There are several negative consequences to including emergency bill assistance within a DSM program:

(i) UNS has proposed a separate DSM per therm charge, and Staff supports this proposal as the preferable method for funding DSM (as discussed later in this testimony). If emergency bill assistance is funded through a separate DSM adjustor it may not be clear to ratepayers that they are also paying for a non-DSM program through the DSM charge;

(ii) funding a non-DSM program through a DSM adjustor reduces clarity regarding the total funding level for actual DSM programs; and

(iii) inclusion of non-DSM components within the DSM program could reduce clarity regarding the objectives of the DSM program.

Staff recommends that the UNS proposal for total DSM spending be reduced by $21,600 and that this amount be funded from base rates and combined, as an additional funding source, with the existing Warm Spirit emergency bill assistance program. Therefore, test year expenses should be increased by $21,600, as discussed in the testimony of Staff witness Ralph Smith.

Q. Did UNS calculate cost-effectiveness or therm savings for the Low-Income Weatherization program?

A. No. The therm savings and cost-effectiveness ratios for the LIW program were requested in Staff's data requests JM 8.7 and JM 8.8. UNS stated that it "did not project cost-effectiveness for the Low-Income Weatherization program" because the program was ordered by Decision No. 59875. Staff's review of Decision No. 59875 shows that the Decision authorized an annual allowance for low-income residential assistance programs, but does not specifically address a weatherization program.

Q. Should the therm savings and cost-effectiveness of the LIW program be determined?

A. Yes. Even though a low-income weatherization program may not be as cost-effective as other DSM programs, it should be as cost-effective as is reasonably possible. Measures included in low-income programs should be generally cost-effective.

UNS' Proposed New DSM Programs

Q. What new DSM programs has UNS proposed?

A. UNS has proposed four new DSM programs, two for Residential customers and two for Commercial customers. The Residential programs consist of (1) Residential Furnace Retrofit; and (2) Residential New Construction. The Commercial programs consist of (1) Commercial HVAC (Heating, Ventilation and Air Conditioning) Retrofit and (2) Commercial Gas Cooking Efficiency. (Exhibit GAS-1; Gary A. Smith testimony, pp. 13-15)

Q. Please describe the selection process and criteria for the proposed UNS DSM programs.

A. UNS reviewed 32 ongoing or proposed programs from Tucson Electric Power, APS, Southwest Gas and the Public Service Company of New Mexico. These programs were ranked according to the following seven criteria:

(i) Applicability to existing customer base;

(ii) Consistency with area demographic and growth trends;

(iii) Potential cost effectiveness;

(iv) High incentive value;

(v) Consistency with societal goals;

(vi) Existing delivery infrastructure; and

(vii) Whether a program complements existing programs.

(Gary A. Smith testimony, pp. 16-17)

Q. How did UNS assess the cost-effectiveness of its proposed DSM programs?

A. UNS used both the Total Resource Cost Test ("TRC") and the Participant Test ("PT") to evaluate the cost-effectiveness of its DSM programs, with the exception of the Low-Income Weatherization program. (Gary A. Smith testimony, p. 17; Exhibit GAS-1) The TRC test compares avoided utility costs against incremental utility and participant costs (excluding incentives paid). The Participant Test compares incentives received and bill reductions against bill increases and incremental participant costs. The Societal Test starts with the Total Resource Cost Test, but includes non-market benefits to society due to DSM, such as reduced environmental effects of energy production and delivery.

Staff recommends that, when filing its detailed program proposals, UNS include the data required to calculate the cost-effectiveness of each program on a Societal Test basis.

Q. Please describe the proposed Residential Furnace Retrofit program.

A. The Residential Furnace Retrofit program is designed to provide residential customers, including multi-family homeowners, with incentives to purchase gas furnaces with an Annual Fuel Utilization Efficiency ("AFUE") of at least 90%. The program would also provide training for contractors to install and operate residential high-efficiency gas furnaces. (Gary A. Smith testimony, p. 13)

Q. What would be the incentive provided under this program, and what is the incremental cost of a high-efficiency gas furnace?

A. The cash incentive for high-efficiency gas furnaces would be $150. (UNS' response to Staff's data request STF 12.7) The total incremental cost of a high efficiency gas furnace, for a furnace at 90-92% AFUE, is $710. (UNS' response to Staff's data request STF 12.7).

Q. Is the Residential Furnace Retrofit program intended to encourage the replacement of functioning standard furnaces with high-efficiency gas furnaces, or is it only intended to replace standard furnaces that are no longer functioning?

A. The incremental cost assumes replacement at the end of a furnace's functional life and does not, for this reason, include labor costs. (UNS' responses to Staff's data request STF 12.2)

Q. What portion of the budget would go to training contractors for the Residential Furnace Retrofit Program?

A. Training is estimated at $5,000 per year. (UNS' response to Staff's data request STF 12.11)

Q. Please describe the proposed Residential New Construction Program.

A. The Residential New Construction Program would provide builders of residential construction projects with incentives to install energy efficiency measures, including improvements to the building envelope and windows; improvements to heating, cooling and water-heating systems; and other measures such as controlled air filtration and tightened air duct systems. (Gary A. Smith testimony, p. 14)

Q. What would be the incentive offered to builders under this program, and what would be the total incremental cost?

A. The UNS Residential New Construction Program would offer an incentive of $400 per house. The estimated incremental cost, per home, is $1,360. This incremental cost covers upgrades to the shell and HVAC equipment. (UNS' response to Staff's data request STF 12.15)

Q. Are any other incentives available to contractors participating in the UNS Residential New Construction program?

A. If builders or contractors construct homes heated or cooled with 50% more energy efficiency than the baseline established in the International Energy Conservation Code, a $2,000 federal tax credit may be available to them under the U.S. Energy Policy Act of 2005 (EPAct 2005). (UNS' response to Staff's data request JM 8.12. (See UNSG0463/04922))

Q. Please describe the proposed Commercial HVAC Retrofit Program.

A. The Commercial HVAC Retrofit Program would provide incentives to business owners to improve the energy efficiency of their gas-fueled space and water heating systems. In addition, training would be provided to contractors, who would also be permitted to take part in a referral program. (Gary A. Smith testimony, p. 15)

Q. Please describe the qualified contractor's referral program.

A. UNS Gas intends to set minimum standards that must be met for a contractor to appear on the referral list, such as licensing, bonding, certifications and records with the Registrar of Contractors and the Better Business Bureau. UNS Gas would publish the referral list on its website and in brochures; a contractor on the referral list would have to resolve UNS customer complaints or be removed from the list. (UNS' response to Staff's data request STF 12.13)

Q. What would be the incentives offered by the Commercial HVAC Retrofit program, and what would be the total incremental costs?

A. The Commercial HVAC Retrofit program would offer a $150 incentive for a small boiler with 84.5% or better efficiency, and a $300 incentive for a large boiler with 85% or better efficiency. Incremental costs for these measures are estimated at $360 and $1,800 respectively. The program would also offer a $150 incentive for a high-efficiency furnace and a $300 incentive for a high-efficiency gas package furnace; the incremental cost of both is $710. (UNS' response to Staff's data request JM 8.12 (see UNSG0463/04919); UNS' response to Staff's data request STF 12.17)

Q. Please describe the proposed Commercial Gas Cooking Efficiency program.

A. Incentives would be provided to operators of commercial kitchens, including business owners, schools and other government facilities, to install high-efficiency commercial gas cooking appliances. (Gary A. Smith testimony, p. 15; UNS' response to Staff's data request JM 8.12 (see UNSG0463/04913); UNS' response to Staff's data request STF 15.12)

Q. What would be the incentives offered by the Commercial Gas Cooking Efficiency program, and what would be the incremental costs of the high-efficiency gas cooking appliances covered by this program?

A. The cooking equipment covered under this program would include energy-efficient fryers, griddles and ovens. The incentives would range from $175 for a griddle, to $750 for Combination, Conveyor or Rotating Rack ovens. Incentives of $500 would be offered for Convection or Deck ovens and for high efficiency fryers. The full incremental costs of the covered equipment are estimated to range from $500 to $3,710 per unit. (UNS' response to Staff's data request JM 8.1 (see UNSG0463/04914); UNS' response to Staff's data request STF 12.20)

Q. How would UNS verify the installation of high-efficiency measures installed under its proposed DSM programs?

A. For the proposed DSM programs, the customer or contractor would be required to supply documentation relating to the purchase and installation of individual high-efficiency measures. In cases where such documentation could not be provided, UNS would perform on-site inspections. Energy efficiency ratings would be verified through manufacturers. Random on-site inspections may also be done in cases where documentation is provided, as a fraud prevention measure. With respect to the Residential New Construction Program, UNS or a UNS-approved contractor would conduct periodic inspections during construction and require documentation from the builder. (UNS' responses to Staff's data requests STF 12.9, 12.10, 12.16, 12.18 and 12.21)

Staff recommends that information regarding verification and inspection be provided by UNS for the LIW program in its program proposals.

Program Administration and Implementation

Q. How would UNS Gas administer its DSM programs?

A. UNS Gas would administer the Residential Furnace Retrofit and Commercial programs on an in-house basis, sharing these duties with UNS Electric in Mohave and Santa Cruz counties, in order to lower administrative costs. For the above three programs, external resources would be used for data entry, inspections and monitoring. For the Residential New Construction Program, UNS Gas and UNS Electric would administer the program in-house in Mohave County, including inspections; outside Mohave County UNS Gas would use external resources for data entry, inspections, builder training and monitoring. For the LIW program, UNS Gas handles payment processing and reporting in-house, while marketing and delivery is handled by outside agencies. (Testimony of Gary A. Smith, p. 18; UNS' responses to Staff's data requests JM 8.10, STF 12.16, STF 15.7 and JM 8. (see UNSG0463/04915, 04928, 04920))

Q. How would UNS Gas and UNS Electric apportion program costs for their jointly administered programs in Mohave and Santa Cruz counties?

A. Program costs would be apportioned according to the energy savings for each energy source. Program costs resulting in electric savings would be allocated to UNS Electric, while program costs resulting in gas savings would be allocated to UNS Gas. However, for Residential New Construction, where there are both gas and electric savings, program costs would be split equally between UNS Gas and UNS Electric. (UNS' response to Staff's data request JM 8.10)

Q. How would program costs for the Residential New Construction program be allocated in areas where UNS Electric is not the electric service provider?

A. In areas where UNS Electric is not the electric service provider, all program costs for the Residential New Construction program would be allocated to UNS Gas. (UNS' response to Staff's data request STF 12.14)

Q. Should UNS file a portfolio plan of its proposed DSM programs?

A. Yes. Staff recommends that UNS file a comprehensive DSM portfolio plan for Commission approval, along with detailed program proposals for each of the new DSM programs it wishes to pursue. Staff also recommends that UNS include, as part of its DSM portfolio filing, information for the LIW program, including data on cost-effectiveness. The filing could be made as soon as UNS has completed it. Staff encourages UNS to file a comprehensive DSM portfolio plan as soon as feasible, rather than waiting for the conclusion of the UNS Electric rate case.

Q. What should UNS include in its overall DSM portfolio plan?

A. The UNS DSM portfolio plan should discuss the portfolio plan itself, followed by program proposals including detailed discussions of each proposed DSM program. The filing should be as detailed as possible, because a high level of detail submitted for each DSM program may make it unnecessary for Staff, or others, to engage in a large amount of discovery. Specific items that should be submitted in the portfolio plan and program proposals include, but are not limited to, the following:

<u>Overall DSM Portfolio Plan</u>

(i) overall portfolio goals and objectives;

(ii) descriptions of all DSM programs to be included in the portfolio;

(iii) estimated levels of energy and capacity savings, utility costs, societal benefits and costs, and other benefits;

(iv) marketing plans;

(v) delivery plans, including implementation schedules;

(vi) measurement and evaluation plans;

(vii) description of the administration of the programs; and

(viii) proposed performance incentives (if any).

<u>Individual DSM Program Proposals</u>

(i) description and concept of the program;

(ii) program objectives and rationale;

(iii) target market segments and program eligibility;

(iv) estimate of baseline conditions;

(v) details on how the program works;

(vi) program products and services;

(vii) program delivery strategy;

(viii) program marketing and communications strategy plans;

(ix) specific DSM measures included in the program;

(x) annual program budget of utility costs broken down by categories, such as rebates and incentives, training, consumer education, marketing, planning and administration;

(xi) how the program is proposed to be funded;

(xii) program implementation schedule timeline;

(xiii) estimates of the anticipated level of program participation;

(xiv) estimated therm saving for each measure or program;

(xv) estimated societal costs of each measure or program, as appropriate;

(xvi) estimated societal benefits from the measure or program, as appropriate;

(xvii) other benefits of the measure or program, as appropriate;

(xviii) net benefits of the measure or program, as appropriate;

(xix) incremental costs for each DSM measure;

(xx) incentives or rebates to be offered (if any);

(xxi) the recipients of incentives or rebates (if any);

(xxii) number of DSM measures expected to be installed;

(xxiii) expected useful life of each unit; and

(xxiv) measurement, monitoring and evaluation procedures for each measure or program.

Monitoring and Evaluation

Q. Should monitoring and evaluation of each program be done, in addition to the verification (e.g., of proper installation) already discussed?

A. Yes. Monitoring can measure the impact of the entire DSM portfolio, to determine whether the resulting incremental benefits to society actually exceed the incremental costs. In addition, monitoring can measure the impact, if any, of each program, to determine whether the individual programs are cost-effective.

Q. What should UNS do if monitoring reveals that a program is not performing to expectations?

A. Monitoring would also allow UNS to refine, correct and modify DSM programs, in order to improve performance. Examples could include increasing or decreasing incentives, revising training programs where there are issues with installation, and broadening or narrowing the advertising programs to ensure that program marketing is effective.

Q. Should UNS terminate approved programs that are not performing to expectations, if modification of the program is not the answer?

A. Yes. If modifying a DSM program does not improve its performance sufficiently to meet the societal cost-effectiveness standard, or if UNS determines that, in its judgment, modification would not bring an under-performing program up to that standard, then UNS should terminate the program. Demand-side management resources should not be expended on ineffective programs.

Q. What should UNS do if it determines that a DSM program should be terminated?

A. First, UNS should inform Staff, in writing, of its decision to terminate a program, including its plans to notify participants, or potential participants. If a program is slated for termination, UNS should both notify participants and potential participants and honor any existing commitments. Existing commitments would include, but not be limited to, payment of incentives to program participants who have purchased energy equipment based on an understanding that their incremental costs would be offset by DSM incentives.

Q. What are Staff's recommendations regarding monitoring plans?

A. Staff recommends that UNS create a monitoring plan for each program and describe these plans in each program proposal.

Q. How should monitoring be conducted?

A. A representative sampling of participants should be monitored for programs with a large number of participants, tracking usage rates and the impact of DSM measures. For programs with smaller participation, most or all of the locations can be monitored to determine the impact of the programs. The impact of weather should be taken into account when monitoring and evaluating the cost-effectiveness of any DSM programs.

Q. How should Staff monitor UNS' DSM programs?

A. In addition to notifying Staff in writing and in advance of any decisions to terminate an approved DSM program, UNS should submit semi-annual reports including the following information:

(i) a brief description of the programs;

(ii) modifications to the programs made during the previous reporting cycle;

(iii) programs terminated during the previous reporting cycle;

(iv) modifications and/or terminations anticipated, if any, during the upcoming reporting cycle;

(v) number of participants, broken down by program;

(vi) number of new residences constructed or measures installed during the previous reporting cycle;

(vii) a description of monitoring activities;

(viii) an evaluation, based on data from monitoring, of each program's performance and cost-effectiveness during the previous reporting cycle;

(ix) therms saved by each program, during the previous reporting cycle;

(x) problems, if any, for each program and proposed solutions;

(xi) progress reports on any previously reported problems;

(xii) costs broken down by type; and

(xiii) research projects, if any, or any other significant information.

Semi-annual reports should be submitted within 60 days after the close of a reporting cycle (January-June and July-December). In addition, the Commission may review the programs in future rate cases.

Marketing and Advertisement of the UNS DSM Programs

Q. How would UNS' DSM programs be marketed and advertised?

A. The Residential Furnace Retrofit, the Commercial HVAC Retrofit and the Commercial Gas Cooking Efficiency programs would be marketed through brochures, bill inserts, customer relations with interest groups and trade market participants, print advertisements, website development (including Energy Advisors), media promotions, presence at conferences and public events and presentation to customers and/or trade allies. The Residential New Construction program would be marketed through brochures for new home purchasers, customer relations with builders, developers and sub-contractors and presentations to developers and trade allies. There would also be training or education seminars tailored to assist participants with the procedural or technical aspects of each program. (Gary A. Smith testimony, pp. 13 and 15; UNS' response to Staff's data request JM 8 (see UNSG0463/04927, 04924, 04914 and 04919))

Marketing of the enhanced LIW program, including the emergency bill assistance component, would be done by the outside agencies currently administering the program. (UNS' response to Staff's data request STF 15.9) Staff recommends that UNS provide more detailed information regarding marketing of LIW in its program proposal.

Cost Recovery of DSM Programs

Q. What is UNS' proposed funding for the entire DSM portfolio?

A. UNS has proposed total funding of $1,051,616 for its DSM programs, including the $21,600 non-DSM emergency bill assistance component of LIW.

Q. What are the alternatives for the recovery of DSM program costs?

A. The alternative methods for recovering the cost of DSM programs include the following: (1) a deferral account with base rate amortization; (2) through base rates with no deferral accounting; and (3) through a PGA.

Q. Should UNS recover its DSM costs through a deferral account with base rate amortization?

A. No. With a deferral account, approved DSM costs are placed in the account to be considered for base rate cost recovery during the next rate case; during the interim, these costs may earn interest. The bank balance, with interest, can result in a major cost that must be resolved during that next rate case. Another disadvantage to a deferral account is that it would not permit timely recovery of DSM costs.

Q. Should UNS recover its DSM costs directly through base rates with no deferral accounting?

A. No. Cost recovery through base rates is current, but inflexible. DSM spending could not be changed between rate cases, so that spending for programs could not be increased or decreased, as needed. In cases where DSM activities were eliminated, this method of cost recovery would leave the DSM funding in place, continuing to collect funds for defunct activities until the next rate case.

Q. Should UNS recover its DSM costs through its PGA?

A. No. While cost recovery would be timely and changes in spending could be made without a rate case, inclusion of DSM charges would complicate administration of the PGA and would potentially decrease transparency regarding both gas costs and the DSM charge. Utilizing this mechanism would also exempt transportation-only customers from paying the DSM charge.

Q. How should UNS recover its costs for its DSM programs?

A. Staff recommends that UNS recover its costs for its DSM programs through a separate DSM adjustment mechanism. A DSM adjustor does not bypass transportation-only customers and provides the advantages of timely cost recovery and flexibility, without complicating administration of the PGA. Another advantage is that a separate DSM adjustor provides more transparency to ratepayers regarding the cost of DSM programs.

Q. How does UNS propose to recover its DSM costs for its new, proposed DSM programs?

A. UNS proposes to recover its costs through an annually adjusted DSM per therm charge. Initially, the DSM charge would be based on DSM annual funding divided by test year therm sales. For example, if UNS' proposed $1,051,616 in funding were approved, it would be divided by 138,233,864 in test year therm sales, to arrive at a $0.007608 per therm charge. (However, Staff recommends that the entire proposed funding not be initially included, as discussed later in this testimony.) In following years, the per therm charge would be based on the requested funding, adjusted for the previous year's over- or under-collection, divided by the projected therm sales. (Tobin L. Voge testimony, p. 18; UNS' response to Staff's data request JM 8.11)

Q. Would cost recovery for the LIW program be treated the same as cost recovery for the other DSM programs in the DSM portfolio?

A. Yes. UNS proposes that the enhanced and reclassified LIW program be funded through the DSM per therm charge. (Gary A. Smith testimony, p. 13; Tobin L. Voge testimony, p. 18)

Q. What costs should UNS be able to recover?

A. UNS should recover the program costs associated with approved DSM projects. These costs include administrative costs, marketing and promotional costs; the cost of incentives, such as rebates; the cost of training associated with DSM programs; and the cost of verifying proper installation and construction.

Q. How would the per therm DSM charge be adjusted each year?

A. Within the DSM portfolio account would be subaccounts for each DSM program where the costs for each DSM program would be separately recorded. By January 31 of each year, UNS would file with the Commission to set the per therm DSM adjustment charge. UNS would provide the documented costs for each subaccount and provide the revenue received from ratepayers through the per therm DSM charge for the previous year. The per therm charge for the next year would be calculated by dividing the account balance by the projected therms for the upcoming year, also adjusting for over- or under-collection. (Schedule 1, Staff Example of DSM Adjustor Calculation)

Q. Which programs should UNS fund using the DSM adjustment mechanism, and when should funding begin?

A. Staff recommends that all DSM programs be funded through the DSM adjustment mechanism, minus the $21,600 LIW emergency bill component. However, initially, only funding for the LIW program should be included in the DSM adjustor; without the emergency bill component, the initial budget would be $113,400 ($135,000 - $21,600). Funding for new DSM programs should not be included in the DSM adjustor at this time. Therefore, Staff recommends that the initial funding be $0.00082 per therm ($113,400 ÷ 138,233,864). The DSM charge would be reset annually on March 1, following the UNS January filing.

Q. What if the LIW program does not appear to be cost-effective?

A. Program elements can be revised to improve cost-effectiveness and remedy or mitigate any other problems with the program. Non-quantifiable societal benefits can be taken into account in evaluation of a program.

Q. How would customers pay for the cost of DSM programs?

A. Customers would pay for the DSM costs, based on therm usage, using a separate line item included on customer bills. (UNS' response to Staff's data request STF 12.5)

Q. What would be the effect of the DSM charge on customer bills?

A. UNS proposes a per therm charge of $0.007608 for its DSM program, including the non-DSM emergency bill assistance component in the LIW program. Under this proposal, residential customers using the July average (for all residential customers) of 15 therms would see a DSM adjustor charge of $0.11; residential customers using the January average of 87 therms (for all residential customers) would see a DSM adjustor charge of $0.66. The per therm charge, based on the entire UNS DSM proposed budget, minus the $21,600 emergency bill assistance component, would be $0.007451. At this level, a residential customer using the July average of 15 therms would still see a DSM charge of $0.11, while customers using the January average of 87 therms would see a DSM charge of $0.65. Staff's recommendation of a an initial DSM charge of $0.00082 per therm would result in a 1 cent charge, while at the January average of 87 therms customers would see a 7 cent charge.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. UNS should continue to work toward expanding participation in the CARES program to additional eligible households.
2. The CARES program monthly customer charge should remain at its current level, and the current per therm discount should be retained.
3. The deferred account for the CARES program should be discontinued.
4. UNS should submit detailed DSM program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case.
5. Emergency bill assistance should not be included in the DSM portfolio. Emergency bill assistance, in the amount of $21,600, should be funded from base rates and combined, as an additional funding source, with the existing Warm Spirit emergency bill assistance program.
6. UNS should file a comprehensive DSM portfolio plan for Commission approval, along with detailed program proposals for each of the new DSM programs it wishes to pursue.
7. When filing its detailed DSM program proposals, UNS should include the data required to calculate the cost-effectiveness of each program on a Societal Test basis.
8. As part of its DSM portfolio filing, UNS should provide information for the LIW program, including marketing, verification and inspection, and cost-effectiveness.

9. UNS should create a monitoring plan for each DSM program and describe these plans in each program proposal.

10. UNS should submit semi-annual DSM reports.

11. UNS should recover its costs for all of its DSM programs through a separate DSM adjustment mechanism. The initial DSM charge, to fund the ongoing LIW program, should be set at $0.00082 per therm.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT A

STAFF HYPOTHETICAL EXAMPLE OF DSM ADJUSTER MECHANISM CALCULATION

FIRST YEAR DSM ADJUSTER	**A**	**B**	**C**	**D**	**E**	**F**	**G**
	ADJUSTED TEST YEAR THERMS	DSM BUDGET	PER THERM DSM CHARGE (B ÷ A)	THERMS SOLD	DSM REVENUE COLLECTED (C X D)	EXPENDITURES	(OVER)/UNDER DSM COLLECTION-BALANCE
	138,233,864	$500,000	$0.003617	140,000,000	$506,380	$600,000	$93,620

$500,000 ÷ 138,233,864 = $0.003617
$0.003617 X 140,000,000 = $506,380
$600,000 - $506,380 = $93,620

SECOND AND SUCCEEDING YEARS	**A**	**B**	**C**	**D**	**E**
	(OVER)/UNDER DSM COLLECTION BALANCE (=G, ABOVE)	DSM BUDGET	DSM BUDGET ADJUSTED FOR (OVER)/UNDER COLLECTION (B + OR – A)	PROJECTED THERM SALES	PER THERM DSM CHARGE (C ÷ D)
	$93,620	$900,000	$993,620	145,000,000	$0.006853

$93,620 + $900,000 = $993,620
$993,620 ÷ 145,000,000 = $0.006853

Note: all numbers, except adjusted test year therms, are hypothetical.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

SURREBUTTAL

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2007

TABLE OF CONTENTS

EXECUTIVE SUMMARY

UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013 AND G-04204A-05-0831

This Surrebuttal Testimony addresses issues raised by UNS Gas, Inc., ("UNS GAS") in its Rebuttal Testimony, including the baseline study proposed by UNS Gas, the CARES program, cost-effectiveness tests, the Demand-Side Management ("DSM") Program Portfolio Plan, the DSM adjustor, the DSM adjustor reset filing deadline, reporting requirements and the adjustment to test year data relating to CARES.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Julie McNeely-Kirwan. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony addressing UNS Gas, Inc.'s ("UNS Gas", "UNS" or "Company") low-income and demand-side management ("DSM") programs.

Q. What is the subject matter of this Surrebuttal Testimony?

A. This Surrebuttal Testimony will address the proposed baseline study, as well as low-income and DSM issues discussed in UNS Gas' Rebuttal Testimony.

BASELINE STUDY

Q. Should a baseline study be done to assist UNS Gas in monitoring the performance of its DSM programs, as proposed by UNS Gas witnesses James S. Pignatelli (p. 9) and Denise Smith (pp. 9-12)?

A. A baseline study would establish the level of natural gas demand and consumption, and the associated costs, that would occur in the absence of a DSM program. Establishing a baseline would provide UNS with valuable information for measuring and improving the cost-effectiveness of its DSM programs. Such a study can also assist UNS in identifying and designing new DSM measures or programs.

Q. Should the cost of the baseline study be recovered through the DSM adjustor, as proposed by Ms. Smith (p. 12)?

A. Yes. Because the purpose of the proposed baseline study is to aid UNS in monitoring the effectiveness of its DSM programs, the cost of the baseline study should be recovered through the DSM adjustor.

Q. Should the cost of the baseline study be included in the DSM adjustor immediately, as proposed by Ms. Smith (p. 12)?

A. No. UNS has not provided an estimate on the cost of such a study. If UNS at a future date provides the estimated cost of the baseline study, Staff will review the reasonableness of such estimate and make appropriate recommendations.

The proposal for the baseline study should be submitted in a separate docket for approval by the Commission.

THE CARES PROGRAM

Q. Do Staff's proposals regarding the CARES rate structure preserve the incentive to conserve?

A. Yes. In Ralph Smith's Surrebuttal Testimony, Staff proposes a rate of $0.3177 for distribution margin therms for all residential customers. Staff also proposes to retain the existing $7.00 monthly customer charge and $0.15 discount on the first 100 therms for CARES customers. (As is currently the case, the $0.15 discount would be in effect only from November through April.) Under Staff's proposals, CARES customers would pay $0.1677 for the first 100 therms and $0.3177 for all therms thereafter. The increased cost of therms over the 100-therm limit provides a price signal and incentive to CARES customers to conserve.

Q. UNS Gas witnesses James S. Pignatelli (p. 13) and D. Bentley Erdwurm (pp. 19-20) state that the UNS proposal does not eliminate incentive to conserve. Does Staff agree?

A. No. The proposed year-round $6.50 monthly discount and flat $0.1862 per-therm charge do not provide as much incentive to conserve as the existing CARES discount, which Staff recommends be retained. Aside from the flat per-therm charge, there is no incentive for CARES customers to conserve; the same discount and the same per-therm charge apply regardless of the number of therms used. Moreover, eliminating the volumetric discount and imposing a flat $0.1862 charge would increase the per-therm price by $0.0358 for usage under 100 therms, while *decreasing* the price for usage above 100 therms during the winter discount period. (The price for each therm over 100 therms used would decrease to $0.1862 from the existing $0.3004).

Although there is still a cost attached to each therm used, a rate that represents an increase for lower therm usage and a decrease for higher therm usage limits the incentive to conserve.

Q. Mr. Erdwurm asserts that the UNS Gas rate design will have a positive impact for all low-usage residential customers (pp. 19-20). Does Staff believe that low-usage CARES customer will experience a positive impact from the UNS rate design?

A. No. The primary reason for this is the increased monthly service charges proposed by UNS for all residential customers. Even with the CARES year-round discount of $6.50, the total annual increase would be $42, or 50 percent above the current annual total of $84. ((8 summer-rate months x $13.50) + (4 winter-rate months x $4.50) = $126.)

For CARES customers, while the "winter" rate is $2.50 per month less than CARES customers are currently paying, the "summer" rate is $6.50 per month more. Also, in terms of the total annual increase in the customer charge, the impact of the higher or "summer" rate is magnified by the fact that the higher rate is charged for eight months of the year, while the lower or "winter rate" is in place for only four months.

Q. What is the annual impact of the UNS Gas proposal on the average CARES customer?

A. For CARES customers in the test year, the total average annual usage was 490 therms. Under the existing structure, the total annual average cost of distribution margin therms and monthly customer charges would be $171.22. Under the UNS proposal, this cost would increase to $217.24 (+$46.02), while under the Staff proposal in Ralph Smith's Surrebuttal Testimony it would increase to $182.07 (+$10.85).

Q. Mr. Erdwurm states, "The objective of the Company's rate design proposal is to correct for the existing subsidy high usage customers in cold climates provide to their counterparts in warm climates. Eliminating this inequity should apply to both non-CARES and CARES customers." (pp. 19-20) Please comment.

A. UNS concerns regarding the cold climate/hot climate subsidy are addressed in Staff witness Ralph Smith's rate design proposal. Under Staff's proposed rate schedule, monthly customer charges have been increased for every rate class except CARES.

Staff does not agree with Mr. Erdwurm's statement that changes designed to eliminate the cold climate subsidy should apply to CARES customers, particularly if those changes include a large annual increase in the monthly customer charge. CARES customers are a protected and explicitly subsidized class of customers, and are the least able to absorb rate increases, regardless of whether they live in warm or cold climates. The value of extending anti-subsidy measures to the CARES rate class is outweighed by the importance of keeping gas rates affordable for low-income customers who otherwise may find themselves unable to pay for gas service. As UNS Exhibit DAS-1 notes, "Low-income persons must often make monthly decisions as to whether to pay rent or mortgage, pay utilities, or buy food." (Northern Arizona Council of Governments (NACOG) letter to Tucson Electric Power, 2/28/07)

ADJUSTMENT TO TEST YEAR DATA (CARES DISCOUNT)

Q. What is the current adjustment arising from UNS' proposal on CARES discounts?

A. On page 4 of UNS Schedule C-2, page 4, in the column for CARES expenses, there is an adjustment of $49,248 under Operating Expenses, Depreciation and Amortization.

The CARES discount proposed by UNS ($441,511) is included in the calculation of the $49,248 adjustment, along with amortized recovery of the balance in the CARES deferred account through the end of the test year. The $441,511 discount represents the total cost of the year-round $6.50 discount on the monthly service charge. (Please see UNS worksheet entitled "Change in Residential Customers by Rate – All Regions," from UNS Gas', Responses to Staff's Data Requests 5.1 and 5.2.)

Q. Is an adjustment to test year data required with respect to Staff's recommendation on CARES discounts?

A. Yes. Staff has not recommended adoption of UNS' proposed discount, above. Under Staff's proposal for the CARES class, the current monthly customer charge and per therm discount are retained, and the foregone revenue is spread through the base rates for all classes. Because the Staff-recommended CARES discount is already included in the rate design, the $441,511 CARES discount proposed by UNS should be removed from Operating Expenses. Staff witness Ralph C. Smith makes the necessary adjustment in his Surrebuttal Testimony, as Adjustment C-20.

Q. Should the Company be allowed to recover the amount accrued in the CARES deferred account?

A. The balance accrued through the test year should be recognized, as stated above. Any balance accrued in the deferred account from the end of the test year through conclusion of the current UNS Gas rate case should be considered for recovery during the next UNS Gas rate case.

COST-EFFECTIVENESS TESTS

Q. UNS witnesses James S. Pignatelli (p. 10) and Denise Smith (p. 3-5, p. 7) express concern regarding Staff's use of the Societal Cost Test to evaluate the cost-effectiveness of DSM programs. Does the Societal Cost Test include a consideration of economic concerns?

A. Yes. Like the Total Resource Cost Test, to evaluate cost-effectiveness, the Societal Cost Test takes into account avoided utility costs as a benefit, balancing this benefit against incremental utility costs (excluding incentives) and incremental participant costs. However, unlike the Total Resource Cost Test, the Societal Cost Test includes avoided environmental impacts as a benefit to be considered in evaluating the cost-effectiveness of a DSM program or portfolio.

Q. Do you disagree with UNS' internal use of other cost-effectiveness tests, in addition to the Societal Test (Smith, pp. 3-7)?

A. No. However, Commission Staff utilizes the Societal Cost Test to evaluate the cost-effectiveness of DSM programs and, to that end, requires information from UNS on the avoided environmental impacts of DSM programs. Even when the value of the impacts cannot be quantified, it can be used qualitatively in evaluating proposed programs, particularly programs where the cost-benefit ratio is close to 1. (Weatherization programs are an example of programs where the cost-benefit ratio can be close to 1.)

Q. Should economic concerns be taken into account when evaluating UNS Gas DSM programs? (Smith, p. 7)

A. Cost-effective DSM is less expensive than acquiring energy supplies, thus benefiting both the utility and ratepayers. Therefore, it is economical for a utility to pursue cost-effective DSM.

DSM PROGRAM PORTFOLIO PLAN

Q. Please comment on Ms. Smith's testimony regarding submission of program proposals and implementation of UNS' DSM programs (pp. 5, 10).

A. Ms. Smith states in her Rebuttal Testimony that UNS has agreed to file detailed program proposals as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case. In fact, UNS docketed its Demand Side Management Program Portfolio Plan ("DSM Plan") on March 23, 2007, as a supplemental exhibit. The UNS DSM Plan has not yet been reviewed in any detail by Staff, but includes information on Low-Income Weatherization ("LIW"), Energy Smart Homes, Efficient Home Heating and the combined program for Commercial Cooking and Heating, Ventilating and Air Conditioning ("HVAC"). UNS states that its DSM Plan will also be filed as part of a separate application for approval. (Ms. Smith advises that, because the UNS Electric case is not concluded, the proposals will include assumptions about joint program implementation and administration with UNS Electric.)

DSM ADJUSTOR

Q. Ms. Smith states that UNS is close to implementing several programs and proposes that half the cost of the new DSM programs be included in the DSM adjustor as soon as the UNS Gas case concludes. This would be in addition to the amounts included for the LIW program and for the baseline study. Does Staff agree?

A. No. Although UNS has submitted its DSM Plan, rather than waiting for conclusion of the UNS Electric case, Staff remains concerned about funding programs either not in operation, or not sufficiently ramped up to require funding at the level of an ongoing program. Given the time required to conclude the UNS Gas case, and for review and possible approval, of the programs, the UNS DSM portfolio may not be fully functional for the entire six months prior to the reset. This could result in over-collection at the DSM adjustor level proposed by UNS.

Staff recommends that the LIW funding ($113,400) and one quarter of the proposed budget for the remaining DSM programs ($229,154 = one quarter of $916,616) be included in the DSM adjustor at the conclusion of the UNS Gas case. Divided by test year therms of 138,233,864, this results in a Staff recommended per-therm DSM adjustor charge of $0.0025. This, Staff believes, strikes a balance between the need to avoid over-collecting and the Company's need to recover costs on a timely basis.

DSM ADJUSTOR RESET FILING DEADLINE

Q. Ms. Smith states (p. 11) that UNS would not have the necessary data to file for the DSM adjustor reset by January 31 and proposes that the filing be done on April 1 of each year, moving the annual adjustment to May 15 or June 1. Does Staff agree with this proposal?

A. Yes. Given Ms. Smith's information, Staff recommends that the DSM adjustor reset filing be done on April 1 of each year, with the annual adjustment moved to June 1. Moving the annual adjustment to June 1, rather than May 15, allows time for the filing to be reviewed and processed, and for the Commission to deal with any issues that may arise.

DSM REPORTS

Q. Ms. Smith proposes to submit DSM reports on an annual basis, rather than a semi-annual basis (p. 10). Does Staff agree?

A. No. Staff recommends that UNS file DSM reports with the Commission on a semi-annual basis, including data on current program spending. Under its proposed DSM Plan, UNS would be implementing multiple, new demand-side management programs. Actual performance is difficult to predict and must be monitored closely, especially in the early phases of a new program. An example would be the need to track the impact of housing market conditions and evolving construction standards on the Residential New Construction/Energy Smart Homes program. Particularly in the early stages of a program, semi-annual reports provide an opportunity for problems to be identified and addressed in a timely fashion.

The semi-annual report should list the costs incurred for each DSM program during the reporting cycle, and include a bank balance for each program.

In its Direct Testimony, Staff recommended that the semi-annual reports should be filed within 60 days after the close of a reporting cycle (January-June and July-December). For simplicity and consistency, the semi-annual reports should be filed on March 1 and September 1 of each year. Filing of the July-December report by March 1 will give Staff time to review and evaluate the performance of UNS' DSM programs prior to the annual adjustor reset.

The question of moving to annual reports can be revisited at a future proceeding, once the UNS programs have been established and are meeting DSM goals in a cost-effective manner.

Q. On page 10 of her testimony, Ms. Smith states, "[S]ince gas consumption in the UNS Gas territory tends to be winter seasonal, a one-year reporting interval is far more meaningful in providing program results information than a six-month interval." Please comment.

A. The DSM programs proposed by UNS will require a variety of year-round activities that should be included in the semi-annual reports. For example, in addition to reporting on the costs and bank balances for each program, there should be reporting on activities such as the number of new, energy efficient homes built or the number of homes weatherized during the reporting cycle. For more information, please see page 25 of my Direct Testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT
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BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF) UNS GAS, INC. FOR JUST AND REASONABLE) RATES AND CHARGES.)	DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013, G-04204A-06-0831

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

PUBLIC UTILITIES ANALYST 5

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

February 9, 2007

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My testimony in this proceeding addresses a number of issues related to UNS Gas Inc.' ("UNS") purchased gas adjustor ("PGA") mechanism. UNS has proposed to make a number of changes to the PGA mechanism and my testimony provides Staff's analysis and recommendations regarding the PGA mechanism.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am a Public Utility Analyst 5 employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst 5.

A. In my capacity as a Public Utility Analyst 5, I conduct analysis and provide recommendations to the Commission on electricity and natural gas matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address UNS' PGA mechanism, including the base cost of gas, in this case.

Q. Have you reviewed the testimony of UNS Witness David Hutchins in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss his proposed changes to the PGA mechanism as part of my testimony.

BASE COST OF GAS

Q. Please discuss the use of a base cost of gas within the overall framework of setting natural gas rates.

A. The base cost of gas has traditionally been used as an estimate of the typical cost of natural gas to UNS and is included in UNS' base rates. The base cost of gas accounts for both the commodity cost and the cost of transporting the natural gas over the interstate pipeline system from its source to UNS' distribution system. UNS uses a PGA mechanism to account for the changing cost of natural gas. UNS currently uses a 12-month rolling average PGA mechanism, whereby a new PGA rate is calculated each month. Each month UNS calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then derived by subtracting the base cost of gas from the 12-month average cost of gas. Therefore, over time, the PGA rate, the base cost of gas, and any temporary PGA surcharge/credit should reflect the total cost of natural gas for UNS. The PGA rate is banded, meaning that each new month when the new PGA rate is set it cannot be set at a rate that is more than $0.10 per therm different than the rate that was in place in any of the previous 12 months.

Q. How has the base cost of gas been dealt with in other recent natural gas rate cases?

A. In recent natural gas rate cases involving Southwest Gas and Duncan Rural Services, the Commission has set the base cost of gas at zero. Traditionally the base cost of gas had been shown as part of the tariffed rate, along with the margin rate which helped recover costs other than the cost of gas. The remainder of the cost of gas was shown as the PGA rate.

Q. What are the practical effects of setting the base cost of gas to zero?

A. Such a change has no impact on the overall rates customers pay or what their monthly bill will be. The primary effect is that by setting the base cost of gas to zero, the cost of gas will be shown as a separate line item on the customer bill, rather than having the base cost of gas component shown as part of the overall tariff rate, which currently makes it more difficult for customers to understand how the changing cost of gas is reflected on their bills. With the zeroing of the base cost of gas, the monthly PGA rate in the future would incorporate the amounts previously shown as the base cost of gas and the monthly PGA rate.

Q. Has UNS made any recommendations regarding the base cost of gas?

A. Yes. UNS has recommended that the base cost of gas be set at zero.

Q. Do you agree with UNS' proposal regarding the base cost of gas?

A. Yes. Staff agrees with UNS' recommendation to set the base cost of gas at zero. This is consistent with recent Commission Decisions regarding Southwest Gas and Duncan Rural Services and will provide a more clear way of representing the cost of gas on customer bills.

Q. Do you have any further recommendations regarding the proposed change to the base cost of gas?

A. Yes. If the base cost of gas is set at zero and the gas cost is fully reflected in a separate line item, this will represent a change in how rates are represented to customers on their bills. Any such change is likely to result in some amount of customer confusion and misunderstanding. Therefore, I recommend that UNS, as part of implementing any change in how gas costs are shown on customer bills, provide specific customer education materials to explain this change. I further recommend that UNS represent the cost of gas as a specific and separate line item on customers bills, noting in a footnote any temporary PGA surcharge or credit that may be in effect.

Q. Are there any issues related to the mechanics of the PGA mechanism that need to be addressed if the base cost of gas is set at zero?

A. Yes. Zeroing out the base cost of gas will cause the monthly PGA rate component to increase a great deal above its current level, well beyond what a typical application of the PGA bandwith would enable the monthly PGA rate to reflect. To address this sizable shift in the monthly PGA rate and allow the PGA mechanism including the PGA bandwidth to continue functioning on a consistent manner, I recommend that when applying the PGA bandwidth for the first twelve months following the implementation of new rates that UNS compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months. This will provide a consistent benchmark for applying the PGA bandwidth while transitioning to a zero base cost of gas.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently effective PGA mechanism was initially implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult for regulators, local distribution companies, and consumers of natural gas. Recent years have also provided a stern test of various aspects of the PGA mechanism. Staff believes that in general the PGA mechanism as currently designed and operated has worked well, given the difficult circumstances of recent years. A PGA mechanism by nature determines the manner in which costs are passed through to customers, including such issues as timing and structure of such pass throughs. In a market where the underlying commodity cost has risen from around $2.50 per mmbtu to $6.00 or so in recent years, any PGA mechanism is going to reflect those higher costs, which will be passed through to customers in some fashion, the only variance being the manner in which the rising costs are passed along to customers. No PGA structure can change the underlying fact that natural gas prices and price volatility have increased dramatically in recent years. In general, Staff believes that the current PGA mechanism reasonably balances the interest in shielding customers from price volatility with the competing desire to at least to some extent send a price signal to customers regarding the changing level of the underlying commodity costs. Nonetheless, it is a worthwhile exercise to evaluate the on-going operation of the PGA mechanism and whether adjustments are warranted. UNS has recommended a number of changes to the PGA mechanism, and my testimony below discusses these proposed changes and Staff's recommendations.

Q. How does the PGA bandwidth aspect of the PGA mechanism work?

A. As currently configured, the PGA bandwidth limits the movement of the monthly PGA rate over a 12-month period. The current PGA bandwidth of $0.10 per therm means that each month when a new PGA rate is calculated, the new monthly PGA rate cannot be more than $0.10 per therm different than the monthly PGA rate in any of the previous 12 months.

Q. Please discuss the history of the PGA bandwidth.

A. When the general PGA mechanism framework now in place was implemented in 1999, the PGA bandwidth was set at $0.07 per therm for Arizona natural gas LDCs. Given the predominantly low and stable natural gas prices through the 1990s, it was generally expected that a $0.07 per therm bandwidth would not come into play very often. However, shortly thereafter the price of natural gas rose significantly and became much more volatile, resulting in the PGA bandwidth often limiting the movement of the monthly PGA rate for periods of time. In Decision Number 62994 (November 3, 2000), the

Commission expanded the PGA bandwidth for Arizona LDCs, including Citizens Utilities Arizona Gas Division (UNS' predecessor) to $0.10 per therm.

Since that Decision the Commission has changed the PGA bandwidth in individual LDC rate cases several times. In Southwest Gas' rate case that concluded in February 2006, the Commission expanded Southwest's PGA bandwidth to $0.13 per therm. In Duncan Rural Services' rate case that was concluded in March 2006, the Commission expanded Duncan's PGA bandwidth such that the monthly PGA rate can change up to $0.10 per therm per month, providing the opportunity for the PGA rate to change up to $1.20 per therm per year. In approving the significant expansion of the PGA bandwidth for Duncan, the Commission cited Duncan's small size and considerable financial constraints.

Q. Has UNS proposed a change to the current PGA bandwidth of $0.10 per therm?

A. Yes. UNS has proposed that the PGA bandwidth be eliminated or in the alternative be set to $0.25 per therm for a period of time before being eventually eliminated.

Q. Please discuss UNS' proposal regarding the PGA bandwidth.

A. UNS' proposal to eliminate the PGA bandwidth would have the effect of allowing the monthly PGA rate to fully reflect changes in the 12-month average cost of gas over time. This would reduce the likelihood of UNS carrying a large PGA bank balance for a sustained period of time and would reduce the need for PGA surcharge/credit filings with the Commission. On the other hand, UNS' proposals would potentially expose UNS' customers to very significant movement in the monthly PGA rate within a 12 month or shorter period, without any form of Commission review or approval.

When the PGA bandwidth was initially implemented in 1999, the purpose was to provide a reasonable range for movement of the monthly PGA rate that would capture the changing cost of gas in most instances and also limit the exposure of customers to an automatically changing PGA rate within a one-year period. To some extent even a PGA bandwidth is limited in its protection of customers anyway, as if gas costs reach a high enough level, UNS will simply apply for a temporary PGA surcharge to capture the higher costs that did not fall within the existing bandwidth. In such cases, the nature of the PGA surcharge would be subject to Commission review and approval, providing additional oversight before large gas cost increases are passed along to customers. The previous expansion of the bandwidth from $0.07 to $0.10 per therm was a recognition that additional flexibility in movement of the monthly PGA rate was needed, while still providing some protection for customers.

Q. What is Staff's recommendation for UNS' PGA bandwidth?

A. Staff is cognizant of UNS' desire for greater flexibility in the PGA bandwidth as well as the need for some amount of checks and balances in how gas costs are passed on to customers, particularly in times when gas prices are high and volatile. In recent cases involving Southwest and Duncan, the Commission has shown a willingness to move toward wider bandwidths. Staff believes that some movement to a wider bandwidth is warranted, but that UNS' proposal to eliminate the bandwidth or expand it to $0.25 per therm is moving too far. Staff recommends an expansion of the PGA bandwidth from the current $0.10 per therm to $0.15 per therm. A $0.15 per therm PGA bandwidth provides significant additional room for movement of the monthly PGA rate, while still providing a reasonable limit on the exposure of UNS' customers to an automatic adjustment without Commission review. Staff believes that a $0.15 per therm bandwidth reasonably balances

Company and customer interests. Further, Staff remains open to consideration of further changes to the PGA mechanism in the future, as may be warranted.

Q. Please describe the function of the PGA bank balance thresholds within UNS' PGA mechanism.

A. The PGA bank balance thresholds identify bank balance levels, whether over-collected or under-collected, where UNS is required to take action at the Commission to either address the over or under-collection, or explain why they should not do so at that given point in time. For UNS' PGA mechanism, the bank balance threshold was initially set at $4.45 million (representing the combined thresholds of the then separate Santa Cruz and Northern Arizona divisions). More recently, in Decision Number 68325 (December 9, 2005) the Commission expanded the threshold level for under-collected PGA bank balances to $6,240,000.

Q. Please discuss why the bank balance thresholds were initially created in 1998 and 1999.

A. At the time the thresholds were initially created, they were created to ensure that PGA bank balance levels did not reach very high levels without any action being taken by the utility. In essence they were a trigger to ensure that the utility and the Commission were aware of and would take action as needed to address the balance. At the time, the initial threshold levels were set at points where it was expected that they would only rarely be breeched. This assumption was based upon the history of natural gas prices through the 1990s, when prices were relatively low and stable. Since the initial implementation of these thresholds, the PGA bank balance level has shown much greater volatility than was seen historically, with changes from month to month at times approaching the size of the threshold. The result is that utilities have exceeded the thresholds relatively often in recent years. In light of these circumstances, Staff believes that reconsideration of the PGA bank balance threshold levels is warranted at this time.

Q. How do you believe the threshold on undercollected PGA bank balances should now be approached?

A. In recent years, local distribution companies ("LDCs") that have filed for PGA surcharges have often made such filings before actually reaching the threshold, in anticipation of breeching the threshold in the near future. LDCs have always had the flexibility to file for a PGA surcharge (or credit) at any time as they see fit. With much higher and more volatile natural gas prices in recent years, both the Commission and LDCs are keenly aware of changes in the PGA bank balance and natural gas market conditions. For a larger LDC like UNS, the Company regularly projects a variety of PGA numbers, including bank balances. Staff believes that these circumstances argue for a change in how the threshold on undercollected PGA bank balances is viewed.

A review of the month to month change in the PGA bank balance is also helpful in assessing the amount of change that has taken place in the PGA bank balance in recent years. Appendix B contains a graph of UNS' PGA bank balance since January 2000 and a graph of the raw size of the change in the PGA bank balance each month. Since January 2000, the largest one month change in the PGA bank balance was approximately $12.9 million, from the end of December 2000 to the end of January 2001. The next largest one month change is $7.6 million, with four other months seeing a change greater than $5 million. The second graph shows that one month changes of $5 million or greater appear to be taking place once or twice a year, with accompanying somewhat smaller changes. A review of the cumulative change over a seasonal timeframe shows a number of occasions where swings in the PGA bank balance are $10 million or more. Given this history of large PGA bank balance swings, retention of the current, relatively small threshold levels indicates the Commission is likely to continue to see filings from UNS to address PGA bank balance levels on a regular basis.

Given these circumstances, Staff believes that for UNS the Commission should consider eliminating the bank balance threshold in relation to under-collected PGA bank balances. Given high and volatile natural gas prices that appear likely to continue in the near term future, both the Commission and UNS carefully monitor the functioning of UNS' PGA, including the changing size of the PGA bank balance. Further, UNS and other LDCs have shown a strong interest in addressing undercollected PGA bank balances on a timely basis, so it is unlikely that UNS' undercollected PGA bank balance would grow to very large proportions without action by the Company. Elimination of the threshold on undercollections would, in essence, provide the utility with the discretion to apply for a PGA surcharge when it believes such an action is warranted, while also providing the flexibility for UNS to avoid such an action if the Company believes changing market conditions do not require such a filing. Staff believes that elimination of the threshold on undercollected PGA bank balances would result in a more smooth operation of the PGA, given the relatively common sizable monthly movements of the PGA bank balance, that at times exceed the size of the threshold itself. Staff therefore recommends elimination of the currently effective threshold on undercollected PGA bank balances.

Q. How does Staff believe that the threshold on overcollected PGA bank balances should be treated?

A. While Staff believes that much of the previous discussion of the threshold on undercollected PGA bank balances also applies to overcollections, there is an additional public interest aspect to avoiding the growth of an overcollected PGA bank balance to exorbitant levels. On the other hand, provision for UNS to carry an overcollection of some size can help provide a cushion to customers when natural gas market prices rise significantly, as has happened a number of times in recent years. Under the current threshold level, any sizable increase in natural gas market prices will likely result in UNS swinging to a sizable undercollected PGA bank balance, even if they had a bank balance close to the current threshold requiring UNS to take action. The current threshold level for overcollections of $4.45 million is sufficiently small that UNS could conceivably exceed the threshold, appear before the Commission to implement a credit, and see their balance swing to a sizable undercollection in a short period of time, with UNS still paying out the credit. Additionally, given volatile market conditions and the size of changes UNS customers have seen over the past years, a refund of $4.45 million over UNS' customer base is a relatively small amount per therm, approximately $0.04 per therm, given recent sales levels.

Staff believes that the cushioning benefit of having a higher threshold level on overcollections, in addition to the administrative efficiency of not having a threshold level that can be easily exceeded in a month, argues for increasing the threshold level on overcollections substantially. The size that such an increase should be is not entirely clear. Staff believes that a reasonable level given UNS' size and on-going market conditions would be $10 million. At such a level UNS could have a sizable cushion for customers against a run up in market prices, while still providing substantial relief to customers when the higher threshold level is breeched. Staff believes that such a higher threshold is both administratively more efficient given significant market volatility, and provides the possibility of a substantive cushion for movement in the PGA bank balance toward an undercollection before customers would be likely to face a PGA surcharge.

Therefore, Staff recommends that the PGA bank balance threshold for overcollections for UNS be set at $10 million dollars.

Q. UNS makes a general proposal on page 15 of Mr. Hutchins' direct testimony that when approving a surcharge, the Commission should approve a surcharge which will eliminate the PGA bank balance in a reasonable time. Please comment.

A. As a general principal, Staff agrees with UNS' sentiment as expressed by Mr. Hutchins on page 15 of his direct testimony, subject to recognition that each time the Commission addresses a PGA surcharge (or PGA credit) there are unique circumstances and changing natural gas market conditions which should be considered. Additionally, it should be noted that the PGA bank balance changes from month to month, often in unexpected directions over time, as weather and other factors impact natural gas market conditions during the period when a PGA surcharge (or credit) may be in effect. So absent a provision that a PGA surcharge (or credit) be in place until the PGA bank balance reaches zero, it will always be uncertain whether a given PGA surcharge (or credit) will eliminate the PGA bank balance that existed at the time such a surcharge (or credit) was implemented.

Q. UNS has proposed changes to the interest rate to be applied to the PGA bank balance. Please describe UNS' proposed changes.

A. UNS is proposing to increase the interest rate applied to the PGA bank balance. It appears UNS is proposing to apply one interest rate, the London Interbank Offered Rate ("LIBOR") plus 1.5 percent, to the portion of the PGA bank balance that is below twice the current PGA bank balance threshold. For the portion of the PGA bank balance above twice the current PGA bank balance threshold, UNS proposed to apply its authorized weighted average cost of capital as determined in this proceeding. It appears that UNS is creating this dividing point by using the current threshold on undercollected PGA bank balances ($6.24 million), rather than the current threshold on overcollected PGA bank balances of $4.45 million. Therefore the split between the two interest rate applications under UNS' proposal would be at $12.48 million.

Q. Please discuss the history of interest being applied to PGA bank balances.

A. Until the Commission adopted the banded 12-month rolling average PGA mechanism in October 30, 1998 (Decision Number 61225), the Commission did not provide for the accrual of any interest on over or under-recovered PGA bank balances. In Decision Number 61225, the Commission approved LDCs, including Citizens Utilities (which subsequently became UNS Gas), to begin applying interest to the PGA bank balances. The approved interest rate at that time was the monthly three month commercial non-financial paper rate, as published by the Federal Reserve. The proposal to apply this interest rate to PGA bank balances was the result of a consensus among working group participants including Staff, the Residential Utility Consumer Office ("RUCO"), Arizona LDCs, and other interested parties. Subsequently, in Decision Number 68600 (March 23, 2006) the Commission approved changing the applicable interest rate for PGA bank balances to the monthly three month commercial financial paper rate published by the Federal Reserve. The purpose for this change was that the previously approved interest rate was no longer being published by the Federal Reserve on a consistent basis, and the new rate was very similar, if slightly higher on average, than the existing rate prior to Decision Number 68600.

Q. Does Staff have concerns with UNS' proposal?

A. Yes. Staff has a number of concerns with UNS' proposal to change the interest rate to be applied to PGA bank balances. Application of different interest rates to different portions of the PGA bank balance adds administrative complexity to the PGA mechanism and absent a compelling need to make multiple interest calculations each month, Staff prefers to apply a single interest rate to the PGA bank balance. Further, Staff is not convinced that a separate interest rate is necessary for the portion of the PGA bank balance above \$12.48 million. While UNS has had a PGA bank balance above \$12.48 million at times in the past, it is important to note that in recent years natural gas prices have been on a general upward trend, so by nature the PGA bank balance will tend toward an undercollection. However, natural gas prices do not always trend upward and the recent trend's impact on UNS' PGA bank balance on recent years should not be assumed to continue into the future. For example, in 2006, natural gas prices generally trended downward, and UNS has now had an overcollected PGA bank balance since the end of June 2006. Further, the Commission could grant a very large PGA surcharge to address a certain size PGA bank balance, but given the vagaries of the natural gas market, the PGA bank balance could still remain undercollected for many months if natural gas prices moved upward during that time. Indeed, in recent PGA surcharge applications, the Commission has considered in its deliberations, information that UNS and other LDCs have provided about their projections of future PGA bank balance levels in an effort to, among other things, avoid large PGA bank balances for long periods of time.

Q. Please discuss the LIBOR rate UNS is proposing to use for the interest rate.

A. It is not entirely clear what specific LIBOR rate UNS is proposing to use or where this rate would be found if the Commission were to adopt it. A review of end of May 2006 LIBOR rates on the British Bankers Association (which publishes the LIBOR) website shows rates ranging from approximately 5.07 percent for the one week rate to 5.42 percent for the one year rate. However, if the rate used in Mr. Hutchins' example on page 13 of his testimony is correct, that the LIBOR rate is relatively similar to the existing interest rate being applied to the PGA bank balance (4.53 percent vs. 4.43 percent), so in that case it would appear that the more significant change is the additional 1.5 percent of interest UNS wishes to collect in addition to the LIBOR.

Q. Has the Commission to date indicated that it wishes to grant interest on the PGA bank balance to an LDC that would exactly match the utility's cost of borrowing to carry any PGA bank balance?

A. No. When the Commission first granted interest on the PGA bank balance in 1999, it was clear that the interest rate being adopted at that time was not equal to any LDC's expected costs of borrowing. Additionally, in rate cases since that time, the Commission has not adopted an interest rate that was considered to be equivalent to the LDC's cost of borrowing. In the recent Southwest Gas rate case (Decision Number 68487, dated February 23, 2006), the Commission adopted an interest rate for Southwest Gas, the one-year nominal Treasury constant maturities rate, that is similar to the current interest rate for UNS. Additionally, the Commission adopted the same interest rate for Southwest Gas as for Arizona Public Service. UNS has not demonstrated that it is somehow so different from other Arizona utilities that it somehow warrants a higher or two-tier interest component.

An additional aspect of this discussion is that the Company's cost of borrowing is likely to change over time, so it is unlikely that there is any simple method of setting an interest rate to specifically track UNS' exact cost of borrowing, even if the Commission wished to do so.

Also, as a general principle, to the extent an LDC receives an interest rate on the PGA balance that might be expected to fully compensate it for the costs of borrowing (or even possibly overcompensate), there could be a concern that the LDC would become less concerned with reducing the PGA bank balance and could become less focused on taking all steps necessary to reduce the cost of natural gas for its consumers.

Further, as was noted in 1999 when the Commission began allowing interest to be collected on PGA bank balances, the higher the interest rate the Commission grants for PGA bank balances, the more the resulting interest will make the PGA bank balance more volatile. The level of such additional volatility is not enormous, but the cumulative effect can be noticeable over time.

Q. Do the other changes Staff is proposing for the PGA mechanism relate to this discussion of the interest rate on the PGA bank balance?

A. Yes. Staff believes that its proposal to substantially expand the band on the monthly PGA rate, in addition to expanding and eliminating the thresholds on the PGA bank balance, will reduce the likelihood of UNS incurring substantial PGA bank balances for long periods of time and provide UNS with additional flexibility in how they respond to on-going changes to the PGA bank balance.

Q. What is your recommendation in regard to the interest rate on UNS' PGA bank balance?

A. Given the circumstances discussed above, Staff believes that the existing interest rate that is applied to UNS' PGA bank balance, the monthly three month commercial financial paper rate, should be retained and is a reasonable balance of UNS' and ratepayer interests. As an alternative, Staff would not oppose moving UNS to the one-year nominal Treasury constant maturities rate.

Q. Do you have any further recommendations regarding the interest rate to be applied to the PGA bank balance?

A. Yes. I recommend that if for some reason in the future the then applicable interest rate becomes unavailable for one or more months, the previous month's interest rate would apply to the month(s) where no interest rate is available. Further, I recommend that if the then applicable interest rate becomes unavailable on a recurrent basis, UNS may file with the Commission to replace the interest rate with another interest rate, with the underlying presumption being that any replacement interest rate would be similar in nature to the then applicable rate.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My testimony includes the following recommendations:

1. The base cost of gas should be set at zero.
2. UNS, as part of implementing any change in how gas costs are shown on customer bills, should provide specific customer education materials to explain this change. I further recommend that UNS represent the cost of gas as a specific and separate line item on customers bills, noting in a footnote any temporary PGA surcharge or credit that may be in effect.
3. During application of the PGA bandwidth for the first 12 months following the implementation of new rates UNS should compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months.
4. The bandwidth on the monthly PGA rate should be expanded to $.015 per therm.
5. The threshold on the PGA bank balance for undercollected balances should be eliminated.

6. The threshold on the PGA bank balance for overcollected balances should be set at $10 million.

7. The currently applicable interest rate for the PGA bank balance should be retained.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Senior Economist (August 1997 - present), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Prepare recommendations and present written and oral testimony before the Commission on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving in my current position as Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee , (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project , (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-060107), Arizona Corporation Commission, May 16, 2006.

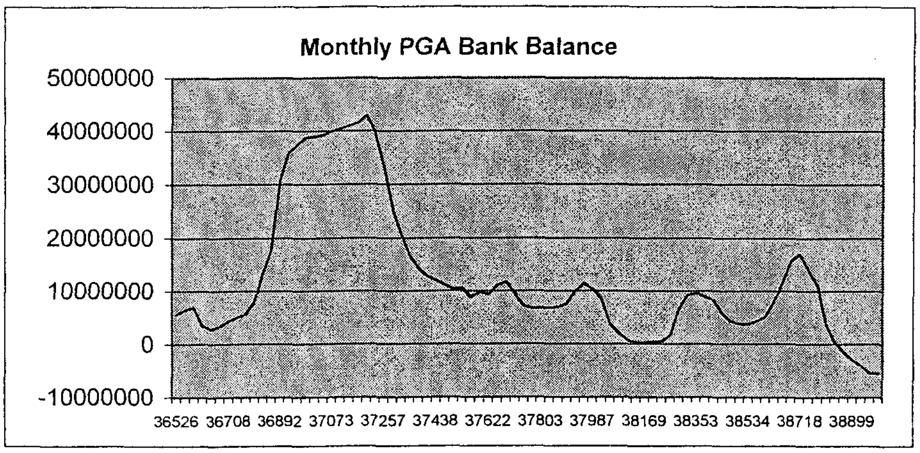
Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2006	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2006	NARUC Winter Committee Meetings
2004-2006	NARUC Annual Convention

Memberships

NARUC - Staff Subcommittee on Gas – Vice-Chair (2002 - 2004)
NARUC - Staff Subcommittee on Gas – Chair (2005 -)
Michigan State Institute for Public Utilities – NARUC Advisory Committee
North American Energy Standards Board Advisory Council

Schedule RGG-2, PGA Bank Balance Information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10000000
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-10000000
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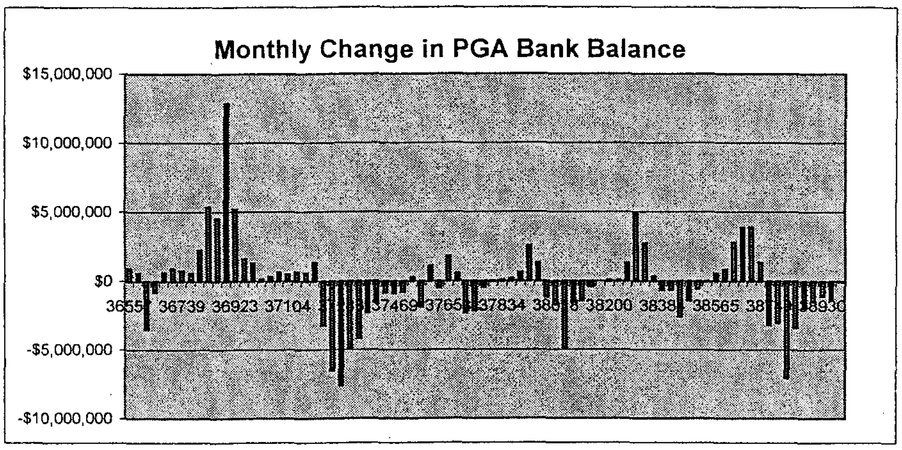
Monthly Change in PGA Bank Balance
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$10,000,000
$5,000,000
$0
-$5,000,000
-$10,000,000
36739 36923 37104 37834 38200 38565

EXHIBIT
ALL-STATE LEGAL®
S-42
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF) UNS GAS, INC. FOR JUST AND REASONABLE) RATES AND CHARGES.)	DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013, G-04204A-06-0831

SURREBUTTAL

TESTIMONY

OF

ROBERT G. GRAY

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

ARPIL 4, 2007

TABLE OF CONTENTS

EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My surrebuttal testimony in this proceeding addresses issues related to UNS Gas Inc.' ("UNS") purchased gas adjustor ("PGA") mechanism. UNS' rebuttal testimony discusses several issues related to the PGA mechanism where UNS' recommendations differ from Staff's. My surrebuttal testimony provides Staff's response to these issues.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am a Public Utility Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Robert G. Gray that filed direct testimony in this case on behalf of Staff?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. This surrebuttal testimony will address portions of UNS Witness Dave Hutchens' rebuttal testimony related to UNS' PGA mechanism.

PURCHASED GAS ADJUSTOR

Q. What position has UNS taken on the PGA bandwidth in Mr. Hutchens' rebuttal testimony?

A. Mr. Hutchens indicates in his rebuttal testimony that UNS believes that removal of the PGA bandwidth is the best long-term solution, but that adoption of the Residential Utility Consumer Office's ("RUCO") proposal of a $0.20 per therm PGA bandwidth is a reasonable compromise in this case.

Q. Mr. Hutchens cites the Commission's action regarding Duncan Rural Services ("Duncan") in Decision Number 68599 (March 23, 2006) as support for UNS' goal of eliminating the PGA bandwidth. Do you agree?

A. No. While the Commission did substantially expand the PGA bandwidth for Duncan in Decision Number 68599, the Commission clearly indicated that such action was based upon the specific circumstances of the Duncan case. In that case the Commission was dealing with a very small natural gas cooperative (approximately 800 customers) with significant financial concerns. Staff does not believe that the Commission's treatment of Duncan is necessarily any indication of how the Commission should, or will, address UNS' PGA bandwidth.

Q. Do you agree with the UNS' proposal to set the PGA bandwidth at $0.20 per therm?

A. Staff continues to believe that its proposal in direct testimony to expand the PGA bandwidth from $0.10 per therm to $0.15 per therm reasonably balances ratepayer and UNS interests. To the extent the PGA bandwidth is expanded further over time, Staff prefers a more gradual approach, with the Commission, Staff, RUCO, and other parties assessing the impacts of a move to a $0.15 per therm PGA bandwidth before possibly considering a larger change in future proceedings.

As has been discussed in the past, the size of the PGA bandwidth reflects a balancing of multiple public policy goals, including timely recovery of gas costs by the utility, reduction of price volatility for ratepayers, and the Commission's interest in reviewing significant changes in rates before they are passed along to ratepayers. Depending on how these public policy goals are balanced, arguments can be made for either increasing, decreasing, or holding constant the PGA bandwidth. As discussed in my direct testimony, I believe an increase in the PGA bandwidth to $0.15 per therm should be adopted at this time.

Q. Have you reviewed the discussion of the interest rate(s) on the PGA bank balance in Mr. Hutchins' rebuttal testimony?

A. Yes.

Q. Are you changing your recommendation?

A. No. For the reasons discussed in my direct testimony, I believe the Commission should retain existing interest rate for the PGA bank balance, rather than adopting UNS' tiered interest rate proposal.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT
S-43
admitted

MEMORANDUM

TO: Ernest Johnson
Director of Utilities

FROM: Robert Miller
Pipeline Safety Supervisor

THROUGH: David Raber
Director, Safety Division

DATE: April 24, 2007

RE: **UNISOURCE RATE CASE**

The Pipeline Safety Section conducts an Annual Code Compliance Audit of Unisource once each calendar year. The most recent audit was completed on June 16, 2006 and conducted by Ryan Weight. The Audit resulted in 5 noncompliance issues including:

1. Failed to follow Quality Assurance Plan.
2. Discovery of inaccessible emergency valves.
3. Inadequate pipe jointing qualification of contractor personnel.
4. Testing of cathodic protection exceeding maximum time intervals.
5. Procedures failed to specify that the interval between manual reviews is not to exceed 15 months.

As of today, the Pipeline Safety Section has verified that the above issues have been corrected and there are no outstanding compliance issues with Unisource.

In addition, I have reviewed the Unisource testimony listing construction build-out projects and associated cost. I have no issues or reasons to disagree with the testimony provided by Unisource.

Please contact me if you have additional questions about this matter.